NEWFOUNDLAND AND LABRADOR
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES
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2015-06-12

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Dear Sirs/Madams:

Re: Newfoundland and Labrador Hydro – Amended General Rate Application – Expert Report – Grant Thornton

Please find enclosed a copy of the Board's expert report received from Grant Thornton in relation to the above-noted matter.

If you have any questions please do not hesitate to contact the undersigned or the Board's Legal Counsel, Ms. Jacqui Glynn, e-mail, jgylnn@pub.nl.ca or telephone (709) 726-6781.

Yours truly,

Sara Kean

Sara Kean
Assistant Board Secretary

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Board of Commissioners of Public Utilities

Financial Consultants Report

Newfoundland and Labrador Hydro

2013 Amended General Rate Application
June 12, 2015

Contents

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our financial analysis of the pre-filed evidence of Newfoundland and Labrador Hydro ("the Company") ("Hydro") which was submitted to the Board in connection with its 2013 Amended General Rate Application ("GRA") seeking approval for changes in rates for each of its customers.

Scope and Limitations

The scope of our financial analysis with respect to Hydro's 2013 Amended General Rate Application and pre-filed evidence is as follows:

1 Review the proposed financial targets including return on equity, debt to capital structure and return on forecast average rate base.

2 Conduct a review of actual and forecast capital expenditures, revenues, expenses, net earnings, return on rate base and return on equity for the years ended December 31, 2007 to 2014, and forecast for December 31, 2014 and 2015.

3 Examine the methodology and assumptions used by the Company for estimating revenues, expenses and net earnings.

4 Review the Company's calculation of estimated average rate base for the year ending December 31, 2014 and 2015.

5 Review the Company's calculation of the proposed rate of return on rate base and return on common equity for the year ending December 31, 2014 and 2015.

6 Conduct an examination of operating expenses, depreciation and finance charges to assess their reasonableness and prudence in relation to sales of power and energy and assess compliance with Board Orders where applicable.

7 Verify the calculation of proposed rates necessary to meet the estimated revenue requirements in the 2015 test year.

8 Review the components and activity of the Rate Stabilization Plan (RSP) included in the Application.

9 Review the intercompany charges and shared services activity included in the test year data.

10 Review the proposed treatment of deferral accounts.

11 Review proposed treatment of actuarial gains and losses on Employee Future Benefits.

12 Review the proposed regulatory treatment of Hydro's Asset Retirement Obligation.

13 Review proposed amortization and recovery mechanisms for Isolated Systems Supply Cost Variance Deferral Account, Energy Supply Cost Variance Deferral Account and the Holyrood Conversion Rate Deferral Account.

14 Review of Hydro's proposal related to changes in functionally oriented Key Performance Indicators.

15 Review of the Rural Deficit Allocation

The nature and extent of the procedures which we performed in our analysis varied for each of the items noted above. In general, our procedures were comprised of:

- enquiry and analytical procedures with respect to financial information in the Company's records;
- examining, on a test basis where appropriate, documentation supporting amounts included in the Company's Application;
- assessing the reasonableness of the Company's explanations; and
- assessing the Company's compliance with Board Orders.

The procedures undertaken in the course of our financial analysis do not constitute an audit of the Company's financial information and consequently, we do not express an opinion on the financial information.

The financial statements of the Company for the year ended December 31, 2014 have been audited by Deloitte & Touche LLP, Chartered Accountants, who have expressed their opinion on the fairness of the statements in their report dated March 18, 2015. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

On April 24, 2015, Hydro provided Revision 1 of NP-NLH-307 to reflect the actual financial numbers for 2014. Where appropriate, the report includes 2014 actuals and explanations of variances from the 2014 test year.

Forecasting Methodology and Assumptions

Based on information provided by Hydro, the Company's 2014 forecast of revenue and expenses was developed based on five months of actual results (January – May) and seven months forecast. The company has noted that the 2014 and 2015 forecasts were projected using the same methodology as the normal operating budget process. In addition, the forecasts incorporate certain assumptions which reflect Hydro's best estimate of future economic conditions and events.

Our approach in this area of our review focused on the following three objectives:

1 Review the methodology used by the Company for forecasting revenues and expenses;

2 Review the assumptions made by management with regard to future economic conditions and events; and,

3 Ensure that these assumptions are properly incorporated into the forecasts.

Methodology

The main steps or components in preparation of the operating budget, as described by Hydro, are as follows:

- The annual budget process commences in July of each year with the issue of detailed budget instructions;

- Operating expenses are budgeted at the Business Unit level. Salaries and benefits, professional fees and operating projects which represent 90% of the operating expense budget were zero based. Other budget expense accounts are escalated at an annual inflation rate over the previous year's budget and adjusted for non-recurring differences. For 2014 forecast the other budget expense accounts were escalated at a rate of 2.2%, while the 2015 other budget expense accounts were escalated at a rate of 2.5%;

- The budget is subject to various levels of review and approval by Managers, Vice-Presidents, the Leadership Team and finally, the Board of Directors of Hydro;

- Load forecasts are prepared by the System Planning department based on forecast information received from Newfoundland Power and the industrial customers, as well as Hydro's own forecast for rural systems. The load forecast is used to generate a revenue budget based on existing rates. For 2015, the proposed new rates were applied to the load forecast to determine the forecast revenue;

- Based on the load forecast, the systems operations department determines the hydraulic/thermal split for generation and calculates and prepares the fuel budget. The purchased power estimates from CF(L)Co. and the non-utility generators (NUGS) are also determined at this time;

- The depreciation expense budget is prepared by the Capital Asset Accounting department based on the capital budget and projected in-service dates for construction projects in progress;

- Depreciation and accretion expense associated with asset retirement obligations are estimated based on timing of the settlement of the obligation;

- Cash expenses associated with operating expense, fuel, power purchases, capital expenditures and revenue inflows are provided to the Treasury department which, based on an interest model, generates a forecast of borrowing requirements and estimated interest expense;

- Capital budgets are submitted to the Board of Directors and PUB for approval;

- Long-term debt related payments are forecast based on debt repayment schedules; and

- All elements of the operating budget are consolidated at this stage and forecast income statement and balance sheet information is submitted to the Leadership Team for their review and approval. After approval at this stage both the operating and capital budgets are submitted to the Board of Directors for final review and approval.

As a result of our review, nothing has come to our attention that causes us to believe that the forecasting revenue, expenses and net income is not consistent with the methodology as described above. Our observations with respect to individual expense estimates and revenue from rates are included within the respective sections of our report that follows.

Review of Assumptions

The key assumptions made by management in developing the test year forecast relate to the following areas:

- the price of No. 6 Fuel for consumption at the Holyrood thermal generating station, the price of No. 2 Fuel for consumption at the Interconnected standby generating plants, and price of diesel for consumption at the diesel plants located throughout isolated parts of Labrador and the island. We requested to review PIRA's No. 6 Fuel price forecast, however under the license agreement for retainer services with PIRA Energy Group, the Company stated they are prohibited from releasing PIRA's proprietary content within the public domain and therefore could not provide PIRA's forecast for the price of No. 6 Fuel;

- Nalcor Energy, operating the Provincial Government's hydroelectric assets on the Exploits River, at Buchans and at Star Lake, supplies the energy to Hydro throughout the forecast period;

- the conversion factor for average efficiency at the Holyrood thermal plant;

- hydraulic production determined by the VISTA model using the forecast methodology as recommended and outlined in Hatch's August 19, 2011 letter: Modelling Approach for Determining System Capability;

- the expected power purchases from the non-utility generators;

- the hydraulic/thermal production split to meet remaining forecast load;

- the load forecasts for Newfoundland Power, the industrial customers and rural interconnected and isolated customers;

- interest rate projections for short and long-term financing;

- negotiated salary increases;

- labour transactions associated with providing or receiving services from or to other lines of business are governed by the Intercompany Transaction Costing Guidelines;
- recovery costs associated with Common Service business units to all lines of business in Nalcor are included in Hydro;
- expenses associated with the Conservation and Demand Management (CDM) Program have been deferred and the recovery mechanism is proposed in the application;
- employee future benefits expense included in operating expenses included actuarial losses, current service costs, interest and other costs;
- expenses relating to the GRA hearing have been deferred and amortized over a three year period beginning January 1, 2015, in addition to $1.0 million that Hydro has included in the 2014 revenue deficiency relating to the 2013 GRA;
- proposed deferral of costs for the following projects, to be amortized over five years:
  - $1.2 million in operating and maintenance costs to be incurred in 2015 for completion of six-year plan initiated in 2010 to bring transformer and breaker maintenance in line with established preventative maintenance frequency;
  - $5.2 million in leasing costs for the Holyrood Black Start Diesel Units;
- depreciation and accretion expense associated with Asset Retirement Obligations (AROs) relating to Holyrood and PCBs are included in operating costs;
- determination of the surplus balance in the RSP is as of December 31, 2015;
- certain assets at the Holyrood Thermal Generating Station have been included in amortization expense using accelerated depreciation; and
- 2014 and 2015 revenue requirement and 2012-2014 actuals have been presented in accordance with P.U.B. 13 (2012), though fiscal years 2007 to 2011 have not been restated.

Where appropriate, Hydro has used information from independent sources and/or expert consultants to establish the assumptions for the above noted items.

The nature of some of the assumptions noted above is that they are constantly being revised and updated by the experts (e.g. fuel prices, interest rates). The load forecasts for Newfoundland Power and the industrial customers are also updated periodically.

Incorporation of Assumptions into Forecasts

The incorporation of the key assumptions into the forecasts was reviewed and agreed to the various schedules included in the Company's pre-filed evidence and other supporting schedules and information provided.

Based upon the results of our procedures we confirm that the assumptions have been appropriately incorporated into the forecasts.

We note that assumptions used in the test year forecast were developed in 2014. As with any forecast, actual results will differ and these differences can be material.

Revenue and Energy Forecasts

Hydro forecasts its revenue based on the total GWh requirements for each of its industrial customers, its utility customer (Newfoundland Power) and its rural customers. These GWh requirements are generally based on operating load forecasts provided in the spring and fall of each year. The fall's operating load forecast allows Hydro to make its initial projections for the following year. This projection is then updated midway through that year when the spring operating load forecast is received. In addition to the fall and spring load forecasts obtained from its industrial customers and Newfoundland Power, these customers also supply Hydro with expected annual production levels and a five year load forecast. The annual production levels help to explain increases or decreases in the anticipated load whereas the five year load forecast allows Hydro to incorporate potential revenues into its own future plans.

In generating the 2014 and 2015 forecast of energy requirements, Hydro relied on the operating load forecasts provided by some of its industrial customers and its utility customer. For the remaining industrial customers, Hydro used its knowledge of each specific industrial end user as well as historical results as its main guide to forecast its energy requirements.

Forecasting energy requirements for rural customers is largely based on historical data. In preparing this forecast a separate projection is prepared for each area of service, namely the island interconnected, the Labrador interconnected and isolated diesel systems. In forecasting the energy requirements for the island interconnected, Hydro relies on a long term econometric model. This model uses both current and historical data to calculate GWh requirements for the coming year. Forecasting for the Labrador interconnected system is based largely on historical trends as opposed to using an econometric model. These trends are then normalized for any unusual weather patterns such as extremely cold or warm winters. Hydro will also incorporate any relevant factors relating to general service customers that may affect load into its equation such as new requests for service, increases in production levels and the installation of new equipment. When forecasting for rural customers whose energy requirements are produced by diesel, Hydro will use many of the same techniques as used in forecasting the Labrador interconnected system. However in doing so, Hydro tends to prepare more detailed forecasts by focusing on each community.

In order to identify any significant trends with respect to sales, we have compared the actual revenues for 2007 to 2014 with the forecast revenues for 2014 and 2015. The results of this analysis of revenue by customer are as follows:

Table 1: Revenue by customer (2007-2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Industrial						
North Atlantic	$ 11,560	$ 12,044	$ 10,669	$ 10,189	$ 9,381	$ 11,432
Abitibi - GF	4,937	5,151	3,352	-	-	-
Abitibi - Stephenville	285	-	-	-	-	-
Corner Brook	19,857	13,762	6,940	5,842	4,198	5,767
Teck Resources	2,812	3,198	3,282	3,530	3,585	3,593
Vale	-	-	-	-	-	5
	39,451	34,155	24,243	19,561	17,164	20,797
Canadian Forces Base	3,951	5,719	1,350	4,025	4,038	1,554
Utility	324,229	321,518	336,626	328,492	355,895	360,961
Rural						
Happy Valley/Wabush	14,245	14,186	14,522	13,479	14,853	15,884
Island Diesel	1,498	1,484	1,538	1,375	1,406	1,424
Island Interconnected	38,907	40,268	39,064	39,592	41,741	43,944
Labrador Diesel	5,737	5,979	6,157	6,177	6,441	6,368
Southern Labrador	1,776	1,885	2,029	2,073	2,258	2,246
	62,163	63,802	63,310	62,696	66,699	69,866
Total revenue from rates	429,794	425,194	425,529	414,774	443,796	453,178
Add:						
Other revenue	1,983	2,197	2,218	2,287	2,317	2,116
Revenue requirement per Finance Schedule I	$ 431,777	$ 427,391	$ 427,747	$ 417,061	$ 446,113	$ 455,294
Percentage change yr over yr		-1.02%	0.08%	-2.50%	6.97%	2.06%

Table 2: Revenue by customer (2013, 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Industrial							
North Atlantic	$ 10,517	$ 11,007	$ 9,978	$ 14,586	$ 490	$ (1,029)	$ 3,579
Corner Brook	3,987	2,717	3,520	4,104	(1,270)	803	1,387
Teck Resources	3,600	3,001	3,451	1,507	(599)	450	(1,494)
Vale	414	4,089	2,454	19,060	3,675	(1,635)	14,971
Praxair	7	869	354	3,262	862	(515)	2,393
IOC - Firm Demand	-	-	-	3,780	-	-	3,780
Wabush - Firm Demand	-	-	-	270	-	-	270
	18,525	21,683	19,757	46,569	3,158	(1,926)	24,886
Canadian Forces Base	333	753	5	932	420	(748)	179
Utility	385,837	417,080	407,328	525,341	31,243	(9,752)	108,261
Rural							
Happy Valley/Wabush	16,031	18,562	17,449	20,534	2,531	(1,113)	1,972
Island Diesel	1,389	1,465	1,401	1,640	76	(64)	175
Island Interconnected	42,385	45,299	44,157	53,108	2,914	(1,142)	7,809
Labrador Diesel	6,049	7,217	6,583	8,881	1,168	(634)	1,664
Southern Labrador	2,236	2,540	2,449	2,962	304	(91)	422
	68,090	75,083	72,039	87,125	6,993	(3,044)	12,042
Total revenue from rates	472,785	514,599	499,129	659,967	41,814	(15,470)	145,368
Add:							
Other revenue	2,343	2,335	2,067	2,508	(8)	(268)	173
Revenue deficiency	-	45,921	45,900	-	45,921	(21)	(45,921)
Revenue requirement per Finance Schedule I	$ 475,128	$ 562,855	$ 547,096	$ 662,475	$ 87,727	$ (15,759)	$ 99,620

The forecast revenue requirement for 2014 was $87.7 million higher than 2013 actuals or 18.5%. This significant increase is primarily due to the revenue deficiency of $45.9 million.

The actual revenue requirement for 2014 was $15.8 million lower than forecast. This is primarily due to a decrease in actual sales over forecast sales. The most significant decrease in sales was 111 GWh to Hydro's utility customer, Newfoundland Power. This decrease in sales accounts for $9.8 million of the variance.

Total revenue from rates is forecast to increase in 2015 by $145.4 million over the 2014 test year. This significant increase is primarily due to the increase in rates incorporated in the 2015 forecast. The forecast of 2015 revenue from rates, using existing rates, is $533.0 million (Table 4.15, p.4.50 of the pre-filed evidence, excluding RSP) compared to the $661.3 million revenues forecast using proposed rates. Therefore, $128.3 million of the increase noted above is due to the proposed increase in rates. The 2015 forecast revenue at existing rates is $18.4 million higher than 2014 test year. These increases would be primarily attributable to changes in load for rural and industrial customers.

In order to identify any trends with respect to forecast load and energy sales, we have compared the actual energy sales (GWh) for 2007 to 2014 with the forecast energy sales for 2014 and 2015. Details of the actual energy sales for 2007-2013 and forecast energy sales for 2014 and 2015 can be found in the pre-filed regulated activities schedules in the 2013 amended GRA. We have also reconciled the total sales forecast to the total GWh generated through hydroelectric, thermal, diesel and purchases of energy. The results of our analysis are as follows:

Table 3: Energy sales (GWh) by customer and reconciliation to energy generated (GWh) (2007 - 2012)

(GWh)	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Industrial						
North Atlantic	243	256	220	206	185	240
Abitibi - GF	122	126	12	-	-	-
Abitibi - Stephenville	3	-	-	-	-	-
Corner Brook	397	283	98	92	55	97
Teck Resources	51	61	65	71	72	72
	816	726	394	370	311	410
Department of National Defence	63	61	19	56	51	18
Iron Ore Company	257	337	162	303	129	180
Utility	4,991	4,960	5,108	5,016	5,318	5,359
Rural - Island Interconnected and Labrador Interconnected	895	910	919	877	968	991
	7,022	6,994	6,602	6,622	6,777	6,958
Transmission and distribution losses - Island Interconnected and Labrador Interconnected	257	288	261	291	290	302
	7,279	7,282	6,863	6,913	7,067	7,260
(GWh)						
Island Interconnected						
Hydroelectric	4,690	4,771	4,200	4,274	4,512	4,595
Thermal	1,256	1,080	940	803	885	856
Diesel	(10)	(8)	(8)	(11)	(9)	(4)
Power Purchases						
NP at Hydro Request	-	-	1	-	-	-
ACI-GF Secondary	64	30	7	-	-	-
Star Lake	148	148	149	136	130	144
Rattle Brook	12	14	16	17	19	15
Corner Brook P&P	-	-	7	4	4	6
Corner Brook Cogen	93	74	56	52	51	48
Exploits River	137	177	180	112	-	-
St. Lawrence Wind	-	8	101	100	110	104
Fermeuse Wind	-	-	54	83	88	91
Nalcor GF, BF and Buchans	-	-	-	-	511	586
	453	450	569	505	911	994
	6,389	6,293	5,700	5,571	6,301	6,441
Labrador Interconnected						
Diesel	(3)	(2)	(2)	(2)	(3)	(1)
Power Purchases	893	991	752	913	783	820
	890	989	750	911	780	819
Total	7,279	7,282	6,451	6,482	7,081	7,260
Difference (Note 1)	-	-	413	431	(14)	-

Note 1: The variances between the energy required and the energy purchased in the years 2009, 2010, and 2011, relate to energy received from Nalcor Exploits base generation which was stored rather than purchased, due to the Abitibi Mill closure in February, 2009.

Table 4: Energy sales (GWh) by customer and reconciliation to energy generated (GWh) (2013 and test years 2014 and 2015)

(GWh)	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Industrial							
North Atlantic	216	231	203	224	15	(28)	(7)
Corner Brook	55	45	66	45	(10)	21	-
Teck Resources	72	56	68	21	(16)	12	(35)
Vale	8	83	48	281	75	(35)	198
Praxair	-	19	7	52	19	(12)	33
	351	433	392	623	83	(42)	189
Department of National Defence	3	9	-	10	6	(9)	2
Iron Ore Company	201	140	124	148	(61)	(16)	8
Utility	5,606	5,963	5,852	5,924	357	(111)	(39)
Rural - Island Interconnected and Labrador Interconnected	1,033	1,097	1,083	1,153	64	(14)	56
	7,194	7,643	7,451	7,859	449	(192)	216
Transmission and distribution losses - Island Interconnected and Labrador Interconnected	322	308	296	283	(14)	(12)	(25)
	7,516	7,951	7,747	8,142	436	(204)	191
(GWh)							
Island Interconnected							
Hydroelectric	4,688	4,703	4,658	4,603	15	(45)	(100)
Thermal	957	1,373	1,315	1,593	416	(58)	220
Diesel	(1)	3	2	11	4	(1)	8
Power Purchases							
NP at Hydro Request	1	3	3	-	2	(0)	(3)
Star Lake	141	145	123	142	4	(22)	(3)
Rattle Brook	15	14	14	15	(1)	-	1
Corner Brook P&P	9	16	20	-	7	4	(16)
Corner Brook Cogen	56	49	48	51	(7)	(1)	2
St. Lawrence Wind	96	100	98	104	3	(2)	4
Fermeuse Wind	96	82	81	84	(14)	(1)	3
Nalcor GF, BF and Buchans	600	612	576	633	12	(36)	21
	1,013	1,020	963	1,030	7	(58)	10
	6,657	7,098	6,938	7,237	442	(162)	138
Labrador Interconnected							
Diesel	1	1	1	1	-	-	(0)
Power Purchases	858	852	808	905	(6)	(44)	53
	859	853	809	906	(6)	(44)	53
Total	7,516	7,951	7,747	8,142	436	(204)	191

Energy sales were forecast to increase overall in 2014 by 436 GWh from 2013 actuals. The largest portion of the increase in the number of GWh in 2014 relates to an increase in energy sales of 357 GWh to Hydro's utility customer, Newfoundland Power. Hydro is also forecasting an increase of 64 GWh in energy sales to rural customers. Newfoundland Power represents Hydro's largest customer with 78% of total GWh forecast to be sold in 2014 before transmission and distribution losses. Newfoundland Power's consumption in 2014 is forecast to increase by 357 GWh or 6.4% over the actual GWh sold in 2013. While the energy requirements for the forecast year are based on Newfoundland Power's operating load forecast provided in 2013, the increase for 2014 is reflective of weather related energy sales and energy sales associated with Newfoundland Power customer growth.

Along with these increases in sales, Hydro is also forecasting 75 GWh increase in energy sales to Vale in 2014 over 2013 actuals. The Vale terminal station was energized in June 2012, with first power taken by the customer in December 2012. According to Hydro, it is anticipated that Vale will increase its levels of demand and energy consumption until it reaches full production levels by the end of 2016.

Decreases totaling 87 GWh are forecast for Corner Brook Pulp and Paper, Teck Resources, and Iron Ore Company of Canada (IOCC) in 2014 test year compared to 2013. 61 GWh of this decrease relates to IOCC and is due to the 2014 arrangements that allowed IOCC to use the excess TwinCo demand and energy which lowered the requirements for IOCC purchases from Hydro.

Energy sales were forecast to increase in 2015 by 216 GWh from 2014 forecasts before transmission and distribution losses. The largest portion of the increase relates to an increase of sales to Vale of 198 GWh. Energy sales are also forecast to increase for Praxair and Rural customers. These increases are partially offset by a decrease in sales to Hydro's Utility customer, due to the expected return to normal weather, and a decrease in sales to Teck Resources as it is expected they will no longer require power and energy from Hydro as of June 2015.

In addition to the analysis of revenue by customer noted above, we also recalculated the 2015 forecast revenue from rates to ensure the proposed new rates together with the forecast loads agree with the test year revenue requirement. Rates for isolated rural government departments were recalculated based on full cost recovery calculated using combined costs for both government and non-government customers. No discrepancies were noted in completing these procedures.

The actual decrease in GWh sold in 2014 was 192 GWh less than forecast before transmission and distribution losses. The largest portion of this decrease related to a decrease in sales of 111 GWh to Hydro's utility customer, Newfoundland Power. This decrease combined with a 28 GWh decrease in sales to North Atlantic and a 35 GWh decrease in sales to Vale make up 174 GWh of the 192 GWh variance.

Cost of Capital

Capital Structure

Hydro's 2014 and 2015 forecast capital structure and projected balance sheet which provides the basis for these calculations is detailed in the pre-filed evidence (finance schedule 1, pg. 2 of 11 and pg. 4 of 11).

Our procedures performed in this area consisted of the following:

- agreed all carry-forward data to supporting documentation;
- agreed all forecast data to supporting documentation to ensure it is internally consistent with the pre-filed evidence and other forecast information; and
- reviewed the clerical accuracy of the calculations of regulated average capital structure.

The Company's calculation of regulated capital structure for 2007 to 2015 is presented in the following tables:

Table 5: Regulated capital structure (2007-2012)

(000,000)'s	As at December 31											
	2007	%	2008	%	2009	%	2010	%	2011	%	2012	%
Debt	$ 1,188	82.6%	$ 1,152	81.5%	$ 981	72.0%	$ 957	72.6%	$ 933	71.7%	$ 957	70.9%
Asset Retirement obligations, funded	-	0.0%	-	0.0%	-	0.0%	-	0.0%	2	0.1%	4	0.3%
Employee future benefits, funded	40	2.8%	42	3.0%	44	3.2%	48	3.7%	54	4.1%	57	4.2%
Equity	211	14.7%	220	15.5%	337	24.7%	313	23.7%	312	24.0%	331	24.5%
	$ 1,439		$ 1,413		$ 1,362		$ 1,318		$ 1,300		$ 1,349	

(000,000)'s	Average									
	2008	%	2009	%	2010	%	2011	%	2012	%
Debt	$ 1,170	82.0%	$ 1,067	76.9%	$ 969	72.3%	$ 945	72.2%	$ 945	71.3%
Asset Retirement obligations, funded	-	0.0%	-	0.0%	-	0.0%	1	0.1%	3	0.2%
Employee future benefits, funded	41	2.9%	43	3.1%	46	3.4%	51	3.9%	55	4.2%
Equity	215	15.1%	278	20.1%	325	24.2%	312	23.9%	322	24.3%
	$ 1,426		$ 1,388		$ 1,340		$ 1,309		$ 1,325	

The company's actual calculation of regulated capital structure for 2013 and 2014 is below, along with a comparison to the calculation for test years 2014 and 2015.

Table 6: Regulated capital structure (2013, 2014 and test years 2014 and 2015)

(000,000)'s	As at December 31							
	Actual 2013	%	(Note 1) Actual 2014	%	Test Year 2014	%	Test Year 2015	
Debt	$ 918	69.6%	$ 1,106	72.1%	$ 1,200	73.2%	$ 1,434	74.8%
Asset Retirement obligations, funded	7	0.6%	10	0.7%	10	0.6%	13	0.7%
Employee future benefits, funded	62	4.7%	67	4.4%	66	4.0%	73	3.8%
Equity	332	25.2%	352	22.9%	363	22.1%	396	20.7%
	$ 1,319		$ 1,535		$ 1,639		$ 1,916	

(000,000)'s	Average							
	Actual 2013		Actual 2014		Test Year 2014		Test Year 2015	
Debt	$ 937	70.3%	$ 1,012	70.9%	$ 1,059	71.4%	$ 1,317	74.1%
Asset Retirement obligations, funded	6	0.4%	9	0.6%	9	0.6%	12	0.7%
Employee future benefits, funded	59	4.4%	65	4.5%	64	4.4%	69	3.9%
Equity	332	24.9%	342	24.0%	348	23.6%	380	21.4%
	$ 1,334		$ 1,428		$ 1,480		$ 1,778	

Note 1: 2014's actual figures are per response to NP-NLH-307 (Revision 1, Apr 24-15) Finance Schedule 1 Page 4 of 11.

Consistent with the Company's calculation of return on equity, equity included in the capital structure shown above excludes Accumulated Other Comprehensive Income.

Prior to 2009, Hydro's debt to equity ratio had been trending towards the 80:20 target ratios with 2008 showing a ratio of 81.5:18.5. In 2009, Nalcor provided a $100 million equity injection of contributed capital resulting in a significant reduction in leverage to a ratio of 72.0:28.0. As can be seen from the above tables, the debt to equity ratio remained relatively consistent from 2009 to 2012 and decreased in 2013 followed by increases in test year 2014 and test year 2015. The increase in the debt to equity in Test Year 2014 and Test Year 2015, compared to Actual 2013, is primarily due to increases in expenditures in property, plant and equipment financed through increases in debt. The increase in the debt to equity ratio for actual 2014 is less than forecast with debt of 72.1% (test year – 73.2%) and equity of 22.9% (test year – 22.1%).

Also in 2009 the Government of Newfoundland and Labrador Order in Council 2009-063 as filed by Hydro in response to NP-NLH-056 provided that the "*capital structure approved by Newfoundland and Labrador Hydro should be permitted to have a maximum proportion of equity as was most recently approved for Newfoundland Power*" (which is currently 45% equity and 55% debt). However, the Company's internal target capital structure is comprised of 75% debt and 25% common equity for regulated operations. Hydro has noted that in order to maintain this target ratio the company implemented the following dividend policy approved by Hydro's Board of Directors in 2009:

"*Corporation annually on or before March 31 of each year, pay a dividend on its common shares if the percentage of debt to debt plus equity in the capital structure of the corporation on a regulated basis at the end of the immediately preceding fiscal year was less than 75% and that the amount of the dividend in that case will be equal to the amount that would be necessary to bring the percentage of debt to debt plus equity up to 75% at December 31st of the immediately preceding year, as if the dividend in question had been on that date.*"

According to Hydro, the corporate regulated capital structure used in the calculation of the regulated dividend is based on a rating agency methodology which differs from the calculation of the capital structure as reported in Hydro's Annual Return 14. For 2009 and 2010, regulated capital structure was calculated based on Dominion Bond Rating Service approach to calculating debt and total capital and for 2011 and 2012 the Standard and Poor's methodology was used. Regulated dividends of $30.9 million and $21.2 million were paid on March 31, 2010 and March 31, 2011 relating to fiscal year ended December 31, 2009 and December 31, 2010, respectively. No regulated dividends were paid on March 31, 2012, March 31, 2013 or March, 2014 relating to the year ends December 31, 2011, December 31, 2012 or December 31, 2013. In addition, no regulated dividends were declared for December 31, 2014. In response to IC-NLH-042 (Revision 1, Dec 3-14) Hydro provided the detailed calculation of the level of dividends under the rating agency methodologies.

Based upon our procedures, we did not note any discrepancies in the calculation of Hydro's capital structure. We do note that Test Year 2015 average capital structure is based on the average of Test Year 2014 forecast capital structure and Test Year 2015 forecast capital structure. As noted in Table 6, 2014 actual capital structure differed from 2014 test year capital structure.

Embedded Cost of Debt

Hydro's calculation of its embedded cost of debt is included in the pre-filed evidence (finance schedule IV Page 1 of 1). We have reviewed these calculations as well as agreed the individual components to supporting documentation including the average total debt, debt guarantee fee, and amortization of foreign exchange losses and accretion of long-term debt. Our specific comments in relation to the debt guarantee fee are included under a separate heading that follows.

The embedded cost of debt for actual 2013, test year 2014 and actual 2014 and test year 2015 is as follows:

Table 7: Embedded cost of debt

(000's)	Actual 2013	Test Year 2014	Actual 2014	Test Year 2015
Interest on Long-Term Debt	$ 90,450	$ 86,288	$ 85,481	$ 95,325
Accretion of Long-Term Debt	540	514	529	495
Amortization of Foreign Exchange Loss	2,157	2,157	2,157	2,157
Debt Guarantee Fee	3,735	3,683	3,683	4,447
Other Interest	14	1,053	891	(1,230)
	96,896	93,695	92,741	101,194
Less:				
Interest on Sinking Fund Assets	(19,434)	(16,026)	(15,935)	(13,413)
Net Interest	$ 77,462 Note 1	$ 77,669	$ 76,806	$ 87,781
Average Total Debt	$ 937,454	$ 1,058,966	$ 1,012,041	$ 1,316,766
Embedded Cost of Debt	8.26% Note 1	7.33%	7.59%	6.67%

Note 1: In Hydro's initial GRA Finance Schedule I Page 4 of 11 and Schedule IV Page 1 of 1, net interest and embedded cost of debt were submitted as $77,806 and 8.30% respectively. In response to our inquires, Hydro noted that the initial GRA submission was an error based on forecast 2013 figures and that the correct figures for net interest and embedded cost of debt were $77,454 and 8.26% respectively.

The methodology and approach used to calculate the test year 2014 and test year 2015 embedded cost of debt is consistent with the 2006 GRA.

Hydro's $125,000,000 Series V debentures which bear interest at 10.5% were repaid to a balance outstanding of $300,000 as of December 31, 2014. During 2014, Hydro issued $200,000,000 Series AF debentures which bear interest at 3.6% and mature in 2045. For test year 2015, Hydro forecasts issuing $400,000,000 of additional debt through a reopening of Series AF debentures. The proceeds are forecast to cover proposed capital expenditures in Labrador West. Hydro expects to refinance or issue new debt at more favourable interest rates. In Hydro's response to PUB-NLH-53 (Revision 1, Nov 28-14) Hydro has estimated its marginal cost of long-term debt at 3.558% as of November 20, 2014. Marginal cost of debt is the cost of another unit of debt raised.

Debt Guarantee Fee

We reviewed the Guarantee Fee Analysis prepared by Scotiabank, dated October 2013. Our comments are based on our experience determining the fees paid for loan guarantees made by parent companies on behalf of their foreign subsidiaries, Canadian law, guidance from the Organisation for Economic Co-operation and Development and the United Nations, as well as jurisprudence from the Tax Court of Canada and Federal Court of Appeal, specifically the *GE Capital* case, in which methodologies for pricing guarantee fees were extensively examined.[1]

For issuing an unconditional guarantee for all of Hydro's debt, the Province of Newfoundland and Labrador (the "Province") charges Hydro a fee equal to 25 bps of the outstanding debt scheduled to mature within 10 years and a fee of 50 bps of the outstanding debt scheduled to mature after 10 years.

The approach used by Scotiabank to measure the value of the guarantee provided by the Province to Hydro is akin to the "yield approach" relied on by Justice Hogan in *GE Capital.* The approach used by Scotiabank compared the yields on bonds issued by the Province with the yields on bonds issued by three Canadian regulated utilities as well as the DEX Universe Utility Index.[2] The differences were believed to represent the 'cost savings' associated with the Province's guarantee, and these 'cost savings' formed the basis for the guarantee fee recommendation. Scotiabank also examined the guarantee fees charged by eight other provinces for use of their respective guarantees. Scotiabank ultimately concluded that the fees charged by the Province to Hydro were still reasonable.

In recent years, methods to price guarantee fees charged by related parties have been subject to substantial scrutiny during international tax examinations and in the courts. As a result of this scrutiny, the yield approach has become the method most often used by transfer pricing practitioners to price guarantee fees between related parties. In the context of Hydro, the first step of the yield approach involves determining the benefit or "cost savings" attributed to the guarantee. This is measured as the difference between the yields on bonds issued by the Province and those issued by Hydro, as a standalone entity. The second step involves apportioning the benefit between the recipient and the guarantor to share in the cost savings, since charging the recipient an amount equal to the benefit would eliminate the incentive for obtaining the guarantee.

All of the bonds issued by Hydro currently have an unconditional provincial guarantee associated with them. Consequently, the yield on those bonds cannot be used to measure the benefit of the guarantee. For this reason, Scotiabank uses the yield on bonds issued by three Canadian utilities as a proxy for the yields on the bonds issued by Hydro, as a standalone entity. However, for this proxy to derive a reliable result, it must be the case that the three Canadian utilities have the same credit rating as Hydro, as a standalone entity.

Since Hydro does not have a standalone credit rating, Scotiabank is implicitly assuming that Hydro has the same credit rating as the three companies without providing any evidence to support such an assumption.

In the event that Hydro did have the same credit rating as one or more of the Canadian utilities used by Scotiabank, three additional issues would rise. First, the three Canadian utilities used have different credit ratings so an adjustment would have to be made to account for the effect of that difference on the yields on the bonds they issued. Second, two of the companies are publicly traded and one of the companies is owned

[1] See *General Electric Capital Canada Inc. v. The Queen, 2009 TCC 563 (Tax Court of Canada)*; and *The Queen v. General Capital Canada Inc. (2010) F.C.A. 344 (Federal Court of Appeal).*
[2] Guarantee Fee Analysis, October 2013, Scotiabank, Pages 3-5.

by a provincial government with a stronger credit rating than the Province. Consequently, adjustments for the relative effect of the implicit support provided would have to be considered. Finally, any effects on the yields from differences in the term to maturity, optionality (i.e.: demand/call options; prepayment options; conversion options), and market-of-issuance would also have to be considered. Without conducting a thorough analysis, it is difficult to determine the impact that these considerations would have on the results derived or conclusions drawn by Scotiabank.

Finally, Scotiabank did not apportion the benefit of the 'cost savings' between the recipient and guarantor. The payment of the entire 'cost savings' associated the guarantee back to the guarantor in the form of a guarantee fee eliminates the incentive for obtaining the guarantee. The average difference between the yield on short-term debt issued by the Province and that issued by the three Canadian utilities ranged from 31.7 bps to 33.0 bps.[3] The 25 bps guarantee fee paid by Hydro for short-term debt implies a 'cost savings' split of 79/21 to 76/24 for the Province/Hydro, respectively.

By comparison, the average difference on long-term debt yields ranged from 35.6 bps to 47.8 bps, already below the 50 bps paid by Hydro.[4] Apportioning the benefits of the guarantee would lower these ranges further, which may bring into question the 50 bps guarantee fee paid by Hydro on long-term debt.

Based on our analysis, further examination is required to determine an appropriate methodology to apportion the benefit of the guarantee between Hydro and the Province on both short-term and long-term debt yields. We recommend that the Board advise Hydro to propose an equitable methodology to apportion this benefit.

[3] Guarantee Fee Analysis, October 2013, Scotiabank, Page 3.
[4] Guarantee Fee Analysis, October 2013, Scotiabank, Page 3.

Regulated Interest Coverage

We have calculated the regulated interest coverage for Test Year 2014 and Test Year 2015 to be 1.69 times and 1.72 times respectively as follows:

Table 8: Interest coverage

(000's)	Test Year 2014	Test Year 2015
Interest on long term debt	$ 87,300	$ 95,300
Add: Interest component of employee future benefit cost	3,600	3,600
Add: Accretion of asset retirement obligation	900	900
Interest, adjusted	$ 91,800	$ 99,800
Net income	$ 30,500	$ 33,200
Add: Amortization, as reported	55,200	63,800
Less: Interest earned, as reported	(16,000)	(14,600)
Less: interest capitalized during construction	(6,100)	(11,000)
Add: Interest on long term debt	87,300	95,300
Add: Interest component of employee future benefit cost	3,600	3,600
Add: Accretion of asset retirement obligation	900	900
EBITDA, adjusted	$ 155,400	$ 171,200
EBITDA, adjusted to interest coverage	**1.69x**	**1.72x**

In 2013, Hydro changed the calculation of its interest coverage to the Standard & Poor's ("S&P") EBITDA interest coverage methodology. The S&P methodology calculates interest coverage as earnings before interest, taxes, depreciation and amortization ("EBITDA") divided by interest. The EBITDA calculation is considered a proxy for cash earnings by S&P. S&P's definition of interest includes the gross amount of interest, including capitalized interest but excluding interest earned. It also includes interest on employee future benefits as well as accretion of asset retirement obligations. The calculations presented in the table have been performed using figures obtained from Finance Schedule I of the GRA.

In response to our requests, Hydro submitted a calculation of interest coverage for Test Year 2014 and Test Year 2015 at 1.77 times and 1.83 times respectively. Our calculations, presented in the table above for Test Year 2014 and Test Year 2015 of 1.69 times and 1.72 times respectively, vary from Hydro's calculations for Test Year 2014 and Test Year 2015 of 1.77 and 1.83 times respectively, due to the treatment of interest capitalized during construction which we interpret as being excluded in calculating EBITDA. In comparison, Hydro's calculation has not excluded interest capitalized from EBITDA in their interest coverage calculations.

Regulated Equity and Return on Equity

Our procedures in this area focused on review of the data incorporated in the calculations and on the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation including the 2013 and 2014 audited financial statements and internal accounting records, where applicable;
- agreed forecast component data (earnings applicable to common equity, dividends, regulated earnings, etc.) to supporting documentation to ensure it is internally consistent with the pre-filed evidence;
- checked the clerical accuracy of the continuity of regulated common equity as forecast for 2014 and 2015;
- recalculated the rate of return on common equity for 2014, forecast 2014, and forecast 2015 and ensured it was in accordance with established practice and applicable Board Orders.

To provide a basis of comparison for average common equity and return on average common equity, we have prepared the following summary for 2010 to 2014 actual as well as test year 2014 and test year 2015. The following table presents the return on book equity calculated using shareholder's equity in Finance Schedule I Page 4 of 11 and regulated earnings from Finance Schedule I Page 1 of 11:

Table 9: Return on book equity

(000)'s		Actual 2010	Actual 2011	Actual 2012	Actual 2013	Test Year 2014	Actual 2014	Test Year 2015
Shareholder's equity	(Note 1)							
2015								$ 395,119
2014						$ 361,887	$ 349,044	$ 361,887
2013					$ 331,383	$ 331,383	$ 331,383	
2012				$ 331,174	$ 331,174			
2011			$ 312,096	$ 312,096				
2010		$ 312,647	$ 312,647					
2009		$ 336,943						
Average equity		$ 324,795	$ 312,372	$ 321,635	$ 331,279	$ 346,635	$ 340,214	$ 378,503
Regulated earnings	(Note 1)	$ 6,604	$ 20,599	$ 16,900	$ 209	$ 30,504	$ 17,661	$ 33,232
Return on book equity		**2.03%**	**6.59%**	**5.25%**	**0.06%**	**8.80%**	**5.19%**	**8.78%**

Note 1: The shareholder's equity and regulated earnings for 2012, 2013, 2014 and test years 2014 and 2015, as filed in the GRA application do not include cost of service exclusions.

The rate of return on book equity calculated in the above summary for the 2014 and 2015 test years is 8.80% and 8.78%. In its Application Hydro proposed a regulated return on equity of 8.80% for the 2014 and 2015 test years, which is a component of the Company's weighted average cost of capital (WACC). Hydro's allowed return is calculated as its rate base multiplied by its WACC (or allowed rate of return).

The regulated return on equity of 8.80% is consistent with Newfoundland Power's return on equity of 8.80% which was approved in Board Order P.U. 13 (2013). Pursuant to Order in Council 2009-063, the Government directed that Hydro would set a target return on equity the same as was most recently set for Newfoundland Power in calculating its return on rate base or calculated through the Newfoundland Power Automatic Adjustment Mechanism. In PUB-NLH-057 Hydro noted that it anticipates future adjustments to its return on equity would only occur as a result of a Hydro GRA, as opposed to future adjustments resulting from a change in Newfoundland Power's allowed return on equity following a subsequent GRA or through the use of an Automatic Adjustment Formula.

The actual shareholder's equity and regulated earnings for 2014 are lower than expected versus 2014 test year by $12,843,000 mainly as a result of lower utility revenues than forecasted. Further commentary on revenue requirement variances from test year and actual 2014 is provided later in our report. This variance resulted in a significantly lower return on book equity of 5.19% for 2014.

Our observations on return on equity, as illustrated in the previous table, indicates a return on equity for Test Year 2015 of 8.78% which differs by 2 basis points from 8.80% used by Hydro in the calculation of WACC in Finance Schedule I Page 4 of 11. However, using a return on equity of 8.78% does not change the WACC calculation of 6.82% as presented by Hydro.

Our observations of return on equity also determined that forecast return on rate base for 2014 test year of 7.12% does not agree to Hydro's forecast WACC of 7.32%. In discussions with Hydro, it was highlighted that this variance in WACC compared to average return on rate base was due to an iteration of return on equity to 8.80% in Test Year 2014 which resulted in a reduction in revenue requirement of $3,300,000, lower regulated earnings and lower return on equity. Had Hydro matched its return on rate base to its 2014 forecast WACC of 7.32%, forecast revenue deficiency would have been higher by $3,300,000 resulting in a return on equity of 9.70%. The exclusion of this revenue deficiency has a favourable impact to ratepayers, with a lower return on equity and return on average rate base.

Based upon our review, we did not note any discrepancies in the calculations of regulated average equity and regulated rate of return on equity. As previously noted, Hydro has requested a rate of return on equity in its Application of 8.80% for both test years 2014 and 2015.

Weighted Average Cost of Capital

The forecast rate of return on rate base is based on the forecast weighted average cost of capital ("WACC"). Hydro's calculation of the WACC is included in the pre-filed evidence on Table 3.11. The inputs to this calculation are the average forecast capital structure and the forecast cost of the individual components of invested capital which include embedded cost of debt and return on equity. Our comments with respect to each of these factors have been provided in the preceding sections.

A comparison of the WACC for actual 2013, actual 2014, 2014 test year, and 2015 test year is included in the table below.

Table 10: WACC

	Actual 2013			Test Year 2014			Actual 2014			Test Year 2015		
	Percent	Cost	WACC	Percent	Cost	WACC	Percent	Cost	WACC	Percent	Cost	WACC
Debt	70.3	8.26%	5.81%	71.4	7.33%	5.24%	70.8	7.59%	5.38%	74.0	6.67%	4.94%
Asset retirement obligations	0.4	0.00%	0.00%	0.6	0.00%	0.00%	0.6	0.00%	0.00%	0.7	0.00%	0.00%
Employee Future Benefits	4.4	0.00%	0.00%	4.4	0.00%	0.00%	4.6	0.00%	0.00%	3.9	0.00%	0.00%
Equity	24.9	4.47%	1.11%	23.6	8.80%	2.08%	24.0	8.80%	2.11%	21.4	8.80%	1.88%
	100.0		6.92%	100.0		7.32%	100.0		7.49%	100.0		6.82%

Compared to actual 2013, WACC is forecast to increase in test year 2014 primarily due to a higher return on equity offset partially by a lower average cost of debt. WACC in test year 2015 compared to test year 2014 is forecast to decrease due to a lower cost of debt, partially offset by a higher debt to equity ratio.

Based upon our review, we did note that in Finance Schedule I Page 4 of 11 and Finance Schedule IV Page 1 of 1 that Hydro initially listed its embedded cost of debt for 2013 at 8.30%. In discussions with Hydro this was acknowledged as an error due to using 2013 forecasted components of embedded interest rather than actual components. Hydro confirmed that the actual embedded cost of debt was 8.26% which was consistent with our calculations for 2013 using actual embedded interest components. The WACC for 2013, submitted on Finance Schedule I Page 4 of 11, of 6.94% changed only marginally to 6.92% based on this correction presented in the table above.

Based upon our review we did not note any discrepancies in the calculation of test year 2014 and test year 2015 WACC of 7.32% and 6.82% respectively.

Average Rate Base and Return on Rate Base

The Company's calculation of its forecast average rate base and rate of return on rate base for the 2014 and 2015 test years is included in Finance Schedule I of the pre-filed evidence. Our procedures with respect to the calculation of the average rate base were directed towards the assessment of the reasonableness of the data incorporated in the calculations and the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation including the 2013 audited financial statements and internal accounting records, where applicable;
- agreed forecast data (capital expenditures, depreciation, etc.) to supporting documentation to ensure it is internally consistent with the pre-filed evidence;
- checked the clerical accuracy of the continuity of the rate base as forecast for 2014 and 2015;
- recalculated the forecast average rate base for 2014 and 2015; and
- reviewed the methodology used in the calculation of the average rate base with reference to the Public Utilities Act, the Hydro Corporation Act and Board Orders.

Details of the 2013 forecast average rate base and return on average rate base with comparative data for 2007, 2008, 2009, 2010, 2011, and 2012, as submitted in Finance Schedule 1, Page 5 of 11, are presented in the following table:

Table 11: Average rate base, return on rate base and rate of return on average rate base (2007-2012)

(000's)	2007	2008	2009	2010	2011	2012
Plant investment (Note 1)	$ 2,016,315	$ 2,044,397	$ 2,082,460	$ 2,136,058	$ 2,191,991	$ 1,510,588
Less: Accumulated depreciation (Note 1)	(570,225)	(603,362)	(632,085)	(669,742)	(707,241)	(88,865)
CIAC's (Note 1)	(96,396)	(96,143)	(96,749)	(97,257)	(98,054)	(14,052)
ARO's	-	-	-	(11,395)	(17,976)	(19,685)
Net capital assets	1,349,694	1,344,892	1,353,626	1,357,664	1,368,720	1,387,986
Balance previous year	1,345,766	1,349,694	1,344,892	1,353,626	1,357,664	1,368,720
Average	1,347,730	1,347,293	1,349,259	1,355,645	1,363,192	1,378,353
Less: average net assets not in use (Note 2)	-	-	-	(777)	(423)	(1,428)
	1,347,730	1,347,293	1,349,259	1,354,868	1,362,769	1,376,925
Cash working capital allowance (Note 3)	3,496	3,548	2,668	3,092	4,625	7,810
Fuel inventory	25,874	34,389	20,817	29,908	33,680	50,308
Supplies inventory	21,699	22,561	23,567	24,089	24,096	25,339
Deferred charges	84,725	81,996	76,870	71,925	68,048	65,670
Average rate base (Note 2)	$ 1,483,524	$ 1,489,787	$ 1,473,181	$ 1,483,882	$ 1,493,218	$ 1,526,052
Return on rate base:						
Unadjusted return on regulated equity	$ 2,711	$ 8,874	$ 17,211	$ 6,604	$ 20,599	$ 16,900
Cost of service exclusions (Notes 2 & 4)	-	-	-	-	-	113
Net interest	103,242	87,610	83,440	86,766	90,844	89,961
Return on rate base	$ 105,953	$ 96,484	$ 100,651	$ 93,370	$ 111,443	$ 106,974
Rate of return on average rate base	7.14%	6.48%	6.83%	6.29%	7.46%	7.01%

Note 1 : In P.U. 13 (2012), the Board approved the use of the carrying value of Hydro's property, plant and equipment as deemed cost at January 1, 2011. As a result, the 2012 balances of plant investment, accumulated depreciation and CIAC's reflect adjustments to deemed cost at January 1, 2011.

Note 2: In P.U. 2 (2012) the Board fixed and determined the 2010 rate base to be $1,484,659,000. Hydro has restated 2010 to exclude average net assets not in service from the average rate base. In P.U. 27 (2014) the Board disapproved capital expenditures for the Charlottetown Diesel Plant. Hydro has restated 2011 and 2012 average rate base to $1,492,796,000 and $1,525,245,000 respectively, to exclude these capital expenditures in response to NP-NLH-307. In addition, as a result of P.U. 27 (2014), return on rate base for 2011 and 2012 has slightly increased by $61,000 and $74,000 respectively to include the effects of cost of service exclusions.

Note 3: Per Finance Schedule I, page 5 of 11, of the pre-filed evidence, the 2009 cash working capital allowance has been restated since the 2009 annual review. Due to a variance in the calculation for the HST adjustment, the allowance has decreased from 2,965,000 to 2,668,000. This change resulted in a decrease of $297,000 in the calculation of average rate base, however it has not impacted the 2009 rate of return on rate base of 6.83%. The difference was determined to be not material by Hydro and the 2009 annual return was not re-filed.

Note 4: The 2012 cost of service exclusion includes an amount for the depreciation of assets not in service. This amount was not included in the 2012 annual review. This change resulted in a increase of $113,000 to the calculation of return on rate base and an increase of 0.01% in the rate of return on rate base.

Details of the 2014 and 2015 forecast average rate base and return on average rate base with comparative data for 2013 are presented in the following table:

Table 12: Average rate base, return on rate base and rate of return on average rate base (2013 and test years 2014 and 2015)

(000's)	2013 (Note 1)	2013 (Note 2)	Test Year 2014	Test Year 2015 (Note 3)
Plant investment	$ 1,603,351	$ 1,603,351	$ 1,840,320	$ 1,921,632
Less: Accumulated depreciation	(138,317)	(138,317)	(193,532)	(254,266)
CIAC's	(15,786)	(15,786)	(16,550)	(18,861)
ARO's	(16,715)	(16,715)	(14,442)	(12,169)
Net capital assets	1,432,533	1,432,533	1,615,796	1,636,336
Balance previous year	1,387,986	1,387,986	1,432,533	1,615,796
Average	1,410,260	1,410,260	1,524,165	1,626,066
Less: average net assets not in use	(7,102)	(8,544)	(2,941)	(2,605)
	1,403,157	1,401,716	1,521,224	1,623,461
Cash working capital allowance	5,875	5,875	9,207	7,037
Fuel inventory	48,949	48,949	65,110	66,633
Supplies inventory	25,763	25,763	25,823	27,402
Deferred charges	64,627	64,627	71,203	77,491
Average rate base	$ 1,548,371	$ 1,546,930	$ 1,692,567	$ 1,802,024
Return on rate base:				
Unadjusted return on regulated equity		$ 209	$ 30,504	$ 33,232
Cost of service exclusions		599	336	323
Net interest		92,394	89,723	89,255
Return on rate base		$ 93,202	$ 120,563	$ 122,810
Rate of return on average rate base		6.02%	7.12%	6.82%

Note 1: As filed in the GRA in Schedule I Page 5 of 11.

Note 2: In P.U. 27 (2014) the Board disapproved capital expenditures for Charlottetown Diesel Plant and Black Tickle Fire Restoration. Hydro has restated 2013 average rate base from $1,548,371,000 (originally filed in Schedule I Page 5 of 11) to $1,546,930,000 in accordance with the Board order and in response to NP-NLH-307.

Note 3: The 2015 test year Plant investment, Accumulated depreciation and CIACs filed in Finance Schedule V page 5 of 11 were misstated compared to prior year presentation. Hydro has provided revised costs reflecting prior year's presentation. The relcassification has no impact on Average Rate Base.

As detailed above, the average rate base is forecast to increase by $145,637,000 in 2014 test year compared to 2013 and $109,457,000 in 2015 test year compared to 2014 test year.

The most significant increase to rate base can be attributable to net capital assets. In 2014, total additions, net of CIAC's of $1.7 million, are forecast in the amount of $268.0 million, of which $29.1 million of assets are included in work in progress and are excluded from 2014 forecast rate base. In 2015, total additions, net of CIAC's of $1.4 million, are forecast in the amount of $282.1 million, of which $198.0 million of assets are included in work in progress and are excluded from 2015 forecast rate base.

Forecast capital expenditures are discussed further in the capital expenditures section of this report.

The decrease in average net assets not in service in forecast 2014 over 2013 of $5,603,000 relates mainly to Holyrood Unit 1 Turbine Generator average net assets in 2013 of $2,703,000, Labrador City Terminal Station average net assets in 2013 of $2,061,000 and Black Tickle Fire Restoration average net assets in 2013 of $695,000. These projects have been included in net capital assets for forecast 2014. Average net assets not in service in forecast 2015 versus forecast 2014 remain at consistent levels.

The cash working capital allowance for 2014 is forecast to increase by $3,332,000 over 2013 primarily due to an increase in operating expenses and power purchases of $21.5 million and lower HST adjustments due in part to higher capital expenditures forecasted in 2014 versus 2013. In 2015, the cash working capital allowance is forecast to decrease by $2,170,000 compared to 2014 test year primarily as a result of higher HST adjustments due to increased revenues and lower forecasted fuel purchases in 2015.

The increase in fuel inventory for forecast 2014 versus 2013 of $16.2 million was described by Hydro as due to higher forecast No. 6 fuel price per barrel and higher inventory requirements for the Holyrood generating station in order to ensure there is adequate fuel supply to reliably meet customer demands. Fuel inventory remains consistent from the period. Fuel inventory remains relatively consistent from forecast 2014 to forecast 2015 at $65.1 million and $66.6 million respectively.

In 2014 forecast, supplies inventory and deferred charges are forecast to remain stable with slight fluctuations over prior year actuals. Supplies inventory remains consistent from forecast 2014 to forecast 2015 at $25.8 million and $27.4 million respectively.

The increase in deferred charges in forecast 2014 over 2013 of $6.6 million relates primarily to Holyrood black start diesel lease cost deferrals of $1.9 million and supply cost deferrals of $5.0 million. Deferred charges are discussed further as a separate section of this report.

The following table is a summary comparing the 2014 test year average rate base and return on average rate base to the company's actual results for 2014.

Table 13: Average rate base, return on rate base and rate of return on average rate base (2014 test year compared to 2014 actual)

(000's)	Test Year 2014	2014	Variance (Actual - Test Year)
Plant investment	$ 1,840,320	$ 1,693,531	$ (146,789)
Less: Accumulated depreciation	(193,532)	(193,143)	389
CIAC's	(16,550)	(17,493)	(943)
ARO's	(14,442)	(14,508)	(66)
Net capital assets	1,615,796	1,468,387	(147,409)
Balance previous year	1,432,533	1,432,533	-
Average	1,524,165	1,450,460	(73,705)
Less: average net assets not in use	(2,941)	(15,201)	(12,260)
	1,521,224	1,435,259	(85,965)
Cash working capital allowance	9,207	8,331	(876)
Fuel inventory	65,110	60,041	(5,069)
Supplies inventory	25,823	26,424	601
Deferred charges	71,203	64,593	(6,610)
Average rate base	$ 1,692,567	$ 1,594,648	$ (97,919)
Return on rate base:			
Unadjusted return on regulated equity	$ 30,504	$ 17,661	$ (12,843)
Cost of service exclusions	336	1,426	1,090
Net interest	89,723	90,051	328
Return on rate base	$ 120,563	$ 109,138	$ (11,425)
Rate of return on average rate base	7.12%	6.84%	-0.28%

The decrease of rate of return on average rate base of 0.28% is due to the decrease in return on rate base, partially offset by a decrease in average rate base. The actual average rate base for 2014 is lower than forecast by $97,919,000 due to the following:

- A decrease in net capital assets of $147,409,000 (average impact $73,705,000) largely related to capital asset expenditures for Hydro's Combustion Turbine forecast to be in service in 2014 but was classified as work in progress and excluded from rate base in 2014 actual. Capital expenditures are discussed further as a separate section of the report.

- A decrease of average net assets not in use of $12,260,000 related mainly to higher than forecast amounts for Holyrood Unit 1 ($5,238,000), Black Tickle ($1,375,000) Labrador City Terminal Station ($4,051,000) and Holyrood Plant Heat Trace ($1,769,000).

- A decrease in fuel inventory of $5,069,000 due to lower than forecast production requirements at the Holyrood generating station.

- A decrease in deferred lease costs of $6,610,000 related primarily to Holyrood black start diesel lease cost deferrals of $1.9 million and supply cost deferrals of $5.0 million which have been excluded from rate base in 2014 actual as the deferrals have not been approved by the Board. Deferred charges are discussed further as a separate section of this report.

The decrease in the return on rate base primarily resulted from a decrease in return on regulated equity, partially offset by an increase in cost of service exclusions and net interest. The decrease in return on regulated equity of $12,843,000 is a mainly a result of lower utility revenues.

Based upon the results of our procedures we note the following:

- In P.U. 27 (2014) the Board did not approve $882,000 of gross expenditures for *The Charlottetown Diesel Plant (2011 Project)*. Hydro initially included the expenditures in its 2011, 2012 and 2013 rate base in its initial GRA and annual return filings. Hydro has subsequently restated its initial filings and excluded the amounts (including related accumulated depreciation) as a component of average assets not in use for purposes of calculation of average rate base for 2011, 2012, 2013 and 2014 as well as forecast 2014 and forecast 2015 in NP-NLH-307.

- In P.U. 27 (2014) the Board did not approve in average rate base $1,374,000 of gross expenditures for *The Black Tickle Fire Restoration*. Hydro initially included the expenditures in its 2013 rate base in the GRA and annual return filings. Hydro has subsequently restated its initial filings in NP-NLH-307 and excluded the amounts (including related accumulated depreciation) from average rate base for 2013 as a component of average assets not in use. In P.U. 27 (2014) it was noted that Hydro may include these expenditures when it applies for its 2013 rate base, provided sufficient evidence is submitted demonstrating the expenditures were reasonable and necessary in the circumstances. These expenditures remain uncertain, and as a result of the GRA, are under prudency review by the Board. Hydro has currently included them in its calculation of rate base for forecast 2014 and forecast 2015. The net book value of the expenditure recorded by Hydro for 2014 is $1,335,000 (cost of $1,417,000 less accumulated depreciation of $82,000). This amount includes 2012 expenditures of $1,374,000 as well as 2013 gross expenditures of $147,000 less insurance proceeds of $104,000 relating to unforeseen items. In P.U. 31 (2013) the Board denied the request to increase the Allowance for Unforeseen items for 2013 capital expenditures in relation to the *Black Tickle Fire Restoration* on the basis that a determination had not been made as to whether the use of the Allowance for Unforeseen Items was in accordance with the Capital Budget Guidelines. The impact of these amounts (factoring related net book value for 2013 of $1,390,000) is an inclusion of $1,362,000 in average rate base for forecast 2014 which is not approved by the Board. For forecast 2015, the net book value of the expenditure is $1,280,000 for an inclusion of $1,307,000 in average rate base which is not approved by the Board.

As a result of completing our procedures, we noted certain project costs are subject to a prudency review by the Board for which approval remains uncertain regarding inclusion in the 2014 and 2015 test year average rate base as follows (including the Black Tickle Fire Restoration project):

Table 14: Project costs for which approval remains uncertain

(000's)	2014 Cost	2014 Accumulated Amortization	2014 Net Book Value	2014 Average Rate Base	2015 Cost	2015 Accumulated Amortization	2015 Net Book Value	2015 Average Rate Base
New Combustion Turbine – Order No. P.U. 16(2014)	$ 110,000.0	$ 261.9	$ 109,738.1	$ 54,869.0	$ 119,000.0	$ 3,426.2	$ 115,573.8	$ 112,656.0
Western Avalon Terminal Station T5 Tap Changer Replacement – Order No. P.U. 7 32 (2014)	1,452.5	3.4	1,449.1	724.5	1,452.5	44.3	1,408.2	1,428.6
Sunnyside Replacement Equipment – Order No. P.U. 29(2014)	3,919.4	9.2	3,910.2	1,955.1	5,145.8	122.5	5,023.3	4,466.8
Holyrood Unit 3 Forced Draft Fan Motor, Overhauls of Sunnyside B1L03 and 28 Holyrood B1L17 230 kv Breakers – Order No. P.U. 23(2014)	598.6	-	598.6	299.3	598.6	105.8	492.8	396.0
Restoration of Holyrood Unit 1 Turbine Generator – Order No. P.U. 14(2013)	5,601.2	977.0	4,624.2	5,015.1	5,601.2	1,758.5	3,842.7	4,233.5
Labrador City Terminal Station Over-Budget Expenditures of $4,194,000 – Order No. P.U. 42(2013)	4,216.8	236.6	3,980.2	4,051.1	4,216.8	378.6	3,838.3	3,909.2
Restoration of Black Tickle Deisel Plant after a Fire - Order No. P.U. 27 (2014)	1,417.0	82.2	1,334.8	1,362.4	1,417.0	137.0	1,280.0	1,307.4
Black Start – Order No. P.U. 38(2013)	800.0	31.0	769.0	400.0	800.0	72.4	727.6	748.3
Total	$ 128,005.5	$ 1,601.3	$ 126,404.2	$ 68,676.6	$ 138,231.9	$ 6,045.3	$ 132,186.6	$ 129,145.8

In conclusion, based on the information presented by Hydro in the previous table, average rate base includes $68,676,600 and $129,145,800 for Test Year 2014 and Test Year 2015 respectively which are subject to a prudency review by the Board, and therefore, inclusion in rate base remains uncertain.

Range of Return on Rate Base

Hydro is proposing 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. A report from Foster Associates, Inc. supporting this position was filed as Exhibit 6 in the Application. 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 Test Year 2015, Hydro is proposing a return on rate base of 6.82%, which under the previously established range would translate to an allowable range of 6.67% to 6.97%. The proposed allowable range of return on rate base would be increased to a range of 6.62% to 7.02%, i.e. ±20 bps.

The following table illustrates the various financial impacts associated with ranges of return on rate base of 30 and 40 basis points for Test Year 2015.

Table 15: Comparison of ranges of rate of return on rate base: 30 and 40 basis points

Comparison of Range of Rate of Return ('000s)

	30 basis points (±15 bps)	40 basis points (±20 bps)	Difference
Average Rate Base	$ 1,802,024	$ 1,802,024	$ -
Rate of Return on Rate Base	$ 122,810	$ 122,810	$ -
Net Income	$ 33,232	$ 33,232	$ -
Return on Rate Base	6.82%	6.82%	-
Return on Equity (ROE)	8.80%	8.80%	-
Return on Rate Base - high	6.97%	7.02%	0.05%
Return on Rate Base - low	6.67%	6.62%	-0.05%
Additional Return = half of bps range	$ 2,703	$ 3,604	$ 901
Additional Return as % of Net Income	8.13%	10.85%	2.72%
Resultant ROE range - high	9.50%	9.80%	0.30%
Resultant ROE range - low	8.10%	7.80%	-0.30%
Implied range of ROE	140 bps (± 70 bps)	200 bps (±100 bps)	60 bps

We have reviewed the pre-filed evidence, including Foster Associates, Inc. Report in Exhibit 6 and offer the following comments:

Higher threshold on upper limit

This proposed change in range of return would have no impact on the determination of the overall revenue requirement for 2015 test year as, the allowed return, as ordered by the Board for setting rates, is the mid-point of the allowed range. Expanding the range of allowed return does however, result in a higher threshold for the upper limit of allowed return on rate base. For 2015, this proposed expansion of the range would represent an increase in the dollar amount of allowed return of approximately $901,000 (40 basis points – 30 basis points ÷ 2 x $1,802,024,000).

Allowed return on rate base and return on equity

The proposed range of 40 basis points for rate of return on rate base assumes a 200 basis point range (±100 bps) for rate of return on regulated common equity, compared to the current 30 basis point range having an implied 140 basis point range (±70 bps) of return on common equity for 2015.

The following table shows the ranges and the impact on the return on equity with a range of 40 basis points (± 20 bps) compared to 30 basis points (±15 bps):

Table 16: Ranges and the impact on the return on equity

2015 TEST YEAR	20 +/- bps				15 +/- bps			
ALLOWED RETURN ON RATE BASE								
	Percent	Cost	WACC		Percent	Cost	WACC	
Debt	74.0	6.67%	4.94%		74.0	6.67%	4.94%	
Asset retirement obligations	0.7	0.00%	0.00%		0.7	0.00%	0.00%	
Employee Future Benefits	3.9	0.00%	0.00%		3.9	0.00%	0.00%	
Equity	21.4	8.80%	1.88%		21.4	8.80%	1.88%	
	100.0		6.82%		100.0		6.82%	
UPPER END OF RANGE								
	Percent	Cost	WACC		Percent	Cost	WACC	
Debt	74.0	6.67%	4.94%		74.0	6.67%	4.94%	
Asset retirement obligations	0.7	0.00%	0.0%		0.7	0.00%	0.00%	
Employee Future Benefits	3.9	0.00%	0.0%		3.9	0.00%	0.00%	
Equity	21.4	9.80%	2.10%	+100 bps	21.4	9.50%	2.03%	+70 bps
	100.0		7.03%	+ 21 bps	100.0		6.97%	+15 bps
				Note 1				
LOWER END OF RANGE								
	Percent	Cost	WACC		Percent	Cost	WACC	
Debt	74.0	6.67%	4.94%		74.0	6.67%	4.94%	
Asset retirement obligations	0.7	0.00%	0.00%		0.7	0.00%	0.00%	
Employee Future Benefits	3.9	0.00%	0.00%		3.9	0.00%	0.00%	
Equity	21.4	7.80%	1.67%	-100 bps	21.4	8.10%	1.73%	+70 bps
	100.0		6.61%	- 21 bps	100.0		6.67%	- 15 bps
				Note 1				

Note 1: As referenced in page 15 and Table 5 of the Foster Associates October 2014 report, the range of return factoring plus or minus one percentage point on return on equity is approximately plus or minus 20 basis points. As illustrated in the table above, the actual impact on rate of return on average rate base is 21 basis points, consistent with the calculations of the Foster Associates report.

The Foster Associates, Inc. report discusses that while the range proposed has increased, referring to the P.U. 40 (2004) and the 2003 capital structure, the implied range of return on equity of ±100 basis points is narrower. The authorized 15 bps range from P.U. 40 (2004) had an implied range of return on common equity of approximately ± 120 basis points or 1.2% due to Hydro lower common equity ratio in 2003 compared to 2015 Test Year.

The same can be illustrated for the 2007 targeted capital structure. The range approved in P.U. 8 (2007) also had an allowable range of return on rate base of ± 15 bps. The implied range of return on common equity was approximately ± 125 basis points (or 1.25%) due to Hydro's lower common equity ratio in 2007 compared to 2015 Test Year.

Utility Comparison

A comparison of the range of return on rate base and implied range of return on equity of Hydro and Newfoundland Power since the 2004 test year is detailed in following table:

Table 17: Comparison of range of return on rate base and implied range of return on equity – Hydro and Newfoundland Power

Newfoundland and Labrador Hydro

	2004 Test Year	2007 Test year	2015 Test Year Based on existing*	2015 Test Year Proposed
Range of Return on Rate Base	±15 bps	±15 bps	±15 bps	±20 bps
Implied Range of Return on Equity	±122 bps	±125 bps	±70 bps	±100 bps

* In P.U. 40 (2004) and P.U. 8 (2007) the Board approved a range of rate of return on rate base for Hydro of 30 basis points (±15 basis points).

Newfoundland Power

	2004 Test Year	2008 Test Year	2010 Test Year	2013 Test Year	2014 Test Year
Range of Return on Rate Base	±18 bps	±18 bps	±18 bps	±18 bps	±18 bps
Implied Range of Return on Equity	±40 bps	~± 38 bps	±40 bps	±40 bps	±40 bps

As illustrated in above table, the allowed range of return on rate base for Newfoundland Power has been consistent at ±18 basis points with an implied range of return on equity of approximately ±40 basis points. Hydro's implied range of return on equity was approximately ±125 basis points in the past two GRAs but will decrease to ±70 basis points if the current approved range of rate of return on rate base of ±15 basis points is applied. The proposed range of return on rate base of ±20 basis points provides an implied range of return on equity of ±100 basis points.

While the conceptual basis for using a range of return is applicable to both Hydro and Newfoundland Power, the differences between the two utilities would suggest that the size of the range of return should be based on the individual circumstances. Foster Associates, Inc. report addresses the differing characteristics of Hydro and Newfoundland Power, such as operating leverage, capital structure and income taxes, and the impact that these differences would have on return on rate base and return on equity. The impact was illustrated in Table 3 of the Foster Associates, Inc. report which shows that a 1% unanticipated increase in expenses would reduce Hydro's return on equity by more than twice as much as it would reduce the return on equity for a utility similar to Newfoundland Power. We agreed the variables included in this table and recalculated similar results. Generally this impact is not unexpected as Newfoundland Power has a stronger capital structure and is a taxable entity.

The variability of Hydro's regulated return on equity relative to Newfoundland Power is shown in the following table:

Table 18: Comparison of return on equity – Hydro and Newfoundland Power

Comparison of Return on Equity - Hydro and Newfoundland Power							
	Actual						
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Return on Equity - Hydro	1.3%	4.1%	6.2%	2.0%	6.6%	5.3%	0.1%
Return on Equity - NP	8.7%	9.1%	9.0%	9.2%	9.0%	9.0%	9.2%

Factors that may impact Hydro's Return on Equity to vary from Target

The examples provided in Foster Associates, Inc. report represent potential variations in earnings that could be significant and include operating expenses, interest expense and higher or lower than expected electricity sales, particularly sales to industrial customers. Due to potential variations in earnings, the allowed range of return on rate base provides for greater rate stability and predictability. However, the use of an expanded range of return on rate base does not protect Hydro from the potential reduction in income that may occur. From a regulatory perspective, the only protection for Hydro from decreases in earnings is through rate adjustments. It is only to the extent there are offsetting earnings fluctuations (both ups and downs) over a period of years that the range of return would act to protect Hydro. Hydro is entitled to recover its cost of service and the appropriate manner in which to recover additional costs is through an application seeking rate relief.

Incentive Mechanism

The use of a range of return on rate base as an incentive mechanism to Hydro with cost management initiatives is an accepted concept in utility regulation. The use of an incentive range together with a period of regulatory lag can be beneficial to ratepayers in the long term. A range of rate of return can provide an incentive to the Company to improve productivity and generate operating efficiencies resulting in lower costs which would be passed on to ratepayers in a subsequent rate hearing. This is consistent with one of the two purposes of the range of allowed return on rate base as noted in P.U. 40 (2004) regarding an incentive mechanism to contain costs by improving productivity, benefiting ratepayers in the long term. The size of the range of return will depend on the assessment of the Board as to the degree of incentive it considers appropriate in the circumstances.

Excess Earnings Account

In its Application Hydro is not proposing any change in the definition of excess earnings as approved in P.U. 40 (2004) other than the change in range from ± 15 bps to ± 20 bps.

Other comments

Foster Associates, Inc. recommends that when the regulated earned return on equity exceeds the target return on equity (even if still earning a return on rate base within the allowed range) by more than one percentage point (100 bps), Hydro include in its annual return filing an explanation of the variance between the actual embedded cost of debt and the cost forecast for the test year and the variance between earned and target return on equity. This would be a similar reporting requirement as Newfoundland Power as was ordered in P.U. 19 (2003), however the threshold for additional reporting for Newfoundland Power is 50 bps.

Based on our review and analysis, while Hydro has proposed an increase in allowed range of return on rate base, the implied range of return on equity is narrower than the two previous GRAs. Additionally, Hydro's return on equity in comparison to Newfoundland Power is more variable when given a set increase in expenses due to the differing characteristics of the utilities, such as capital structure and income tax status.

The recommendation of the Foster Associates, Inc. report, that the Board consider an annual reporting requirement for Hydro, is consistent with the policy currently in place for Newfoundland Power when regulated earned return on equity exceeds the target return on equity by more than one percentage point.

2014 Revenue Deficiency

In its amended application, Hydro is forecasting a revenue deficiency in 2014 of $45.9 million, which excludes approximately $10 million in increased 2014 supply costs. The forecasted deficiency is a result of existing rates being inadequate to recover Hydro's revenue requirement, which includes a return on equity of 8.80%. The following is a summary of the 2014 revenue deficiency compared against actual results for 2014:

Table 19: 2014 Revenue Deficiency

2014 Revenue Deficency
$ Millions

Cost Type	2014 Test Year	2014 Actual	Change	Reference	Page No.
Other Costs	128.1	134.0	5.9	**Other Costs**	**60**
Accretion of Asset Retirement Obligation	0.8	0.8	-	**Accounting Matters**	**126**
Fuel, net of RSP	201.8	195.2	(6.6)	**Revenue Requirement**	**47**
Recovery of Additional Supply Costs	(10.0)	(9.7)	0.3	**Note 1**	
Power Purchases	66.7	63.7	(3.0)	**Revenue Requirement**	**52**
Depreciation	55.2	55.3	0.1	**Revenue Requirement**	**45**
Return on Equity	30.5	17.7	(12.8)	**Regulated Equity and Return on Equity**	**22**
Interest	89.7	90.1	0.4	**Revenue Requirement**	**57**
Total Revenue Requirement	562.8	547.1	(15.7)		
Less: Revenue at Existing Rates	(516.9)	(501.2)	15.7	**Revenue and Energy Forecasts**	**9**
2014 Revenue Deficiency	45.9	45.9	-		
Supply Costs Revenue Deficiency	10.0	9.7	(0.3)	**Note 1**	
Total	**55.9**	**55.6**	**(0.3)**		

Note 1: The test year included costs of $10 million, which varies from the subsequently filed application to the Board of $9.7 million.

Each of the variances between the 2014 test year and actual results are discussed further in other sections of our report. We have referenced the appropriate sections in the table above.

Hydro has proposed that the revenue deficiency be offset against the RSP credit balance in the Hydraulic Variance Account at December 31, 2014. Hydro stated in its application that "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 P.U. 58 (2014), the Board approved the creation of the deferral account but denied the request to recover the amount from the Hydraulic Variance Account.

We requested that Hydro calculate the impact on the 2014 revenue deficiency of each of the 11 items being addressed assuming that the recovery of all costs (both capital and operating) associated with the 11 items currently in the prudency review is denied by the Board. The response to this request is outstanding and an update to this section will be released when completed.

2014 and 2015 Revenue Requirement

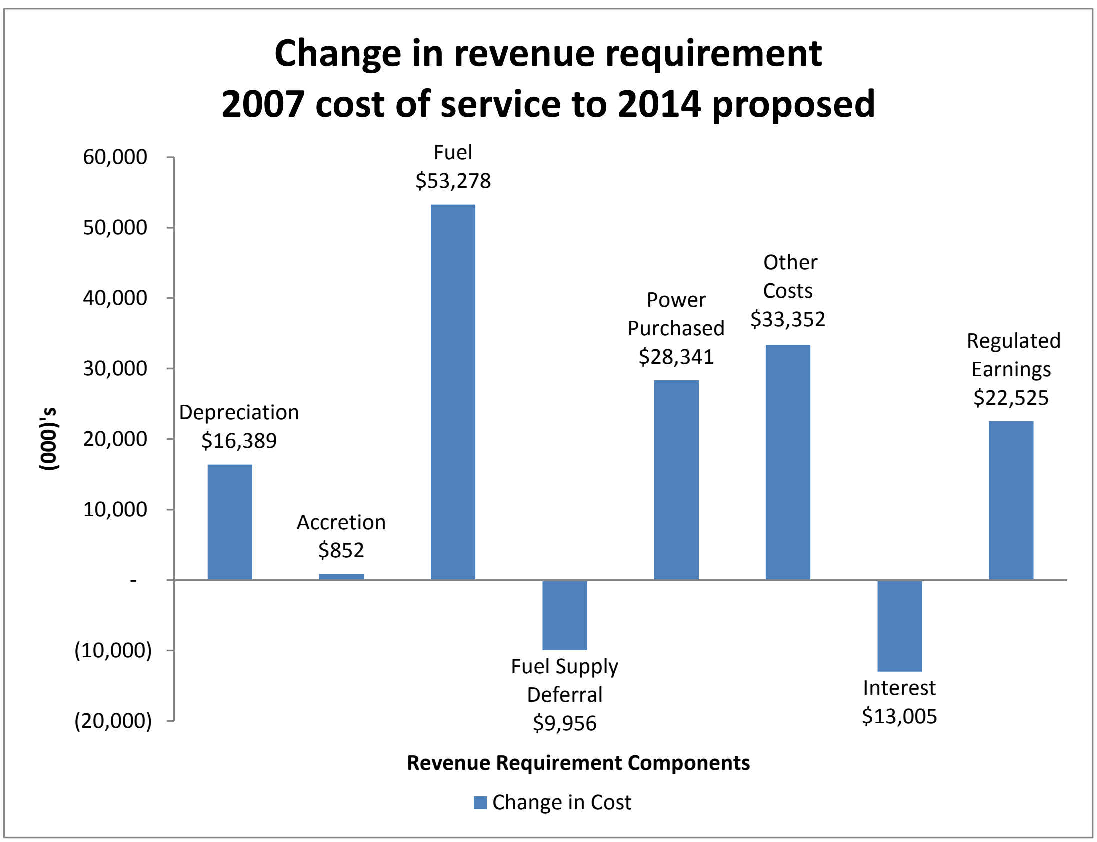
Comparison of 2007, 2014 and 2015 Test Years

The following table and graph summarize the changes in Hydro's revenue requirement from the 2007 Test Year to the 2014 and 2015 Test Years.

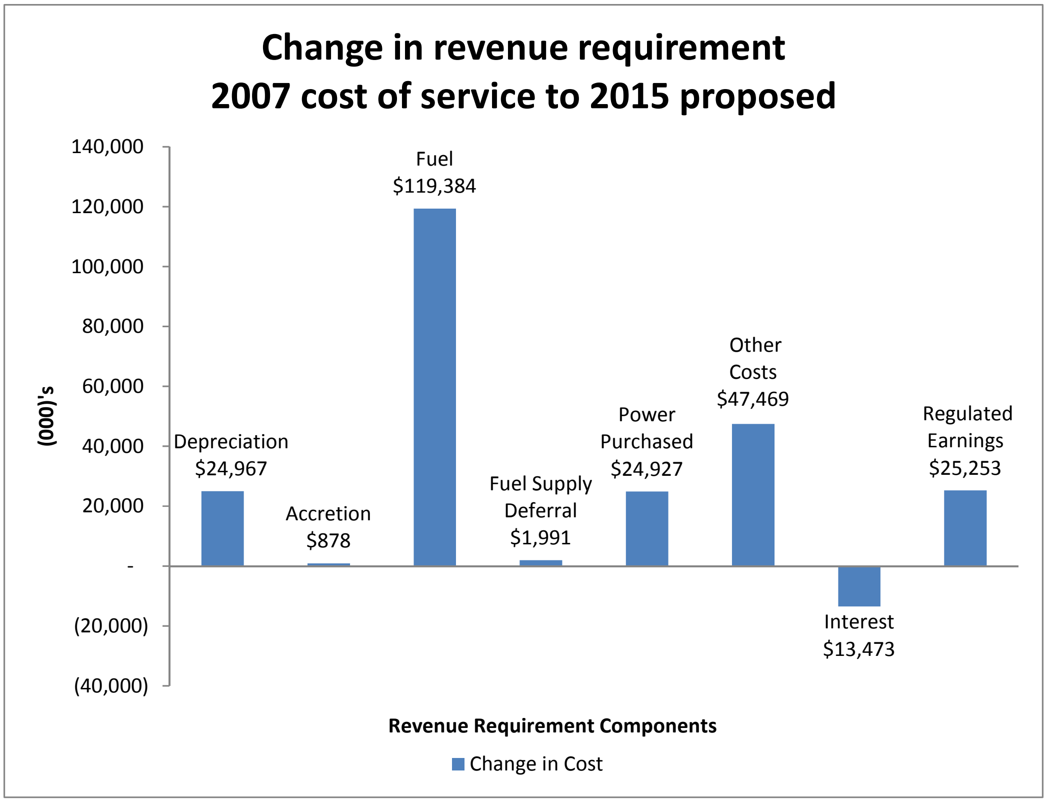
Table 20: Change in revenue requirement from 2007 test year to 2014 and 2015 test years

(000)'s	2014	2015
2007 Revenue Requirement	$ 431,079	$ 431,079
Increase (decrease)		
Depreciation	16,389	24,967
Accretion of ARO	852	878
Fuel	53,278	119,384
Fuel Supply Deferral	(9,956)	1,991
Power purchased	28,341	24,927
Other costs (net)	33,352	47,469
Interest	(13,005)	(13,473)
Regulated earnings	22,525	25,253
Revenue Requirement	$ 562,855	$ 662,475

Graph 1: Change in revenue requirement from 2007 test year to 2014 test year



Graph 2: Change in revenue requirement from 2007 test year to 2015 test year



The following table provides the cost per kWh for the 2007, 2014 and 2015 Test Years.

Table 21: Cost per kWh – 2007, 2014 and 2015 test years

	Cost per kWh
Test Year 2007	0.0589
Test Year 2014	0.0750
Test Year 2015	0.0859

The revenue requirement for the 2014 test year has increased over the 2007 test year by $131.8 million or 30.6% and the 2015 test year has increased over the 2007 test year by $231.4 million or 53.7%. While each component of the 2014 and 2015 revenue requirements has increased significantly over the 2007 test year (with the exception of interest), the largest contributor for both is the cost of fuel.

The $53.3 million and $119.4 million increases in the forecast fuel expense for 2014 and 2015 respectively are primarily due to increases in costs for No.6 fuel as a result of increases in fuel price and lower fuel conversion performance at Holyrood Thermal plant. For the 2007 test year, the average consumption price per barrel was $55.47. However, for the 2014 and 2015 test years, Hydro received forecasts from PIRA Energy Group in September 2014 which showed they are estimating an average cost of $106.46 and $90.85 respectively which results in an average consumption price of $109.59 per barrel in 2014 and $93.32 per barrel in 2015.

The “consumption price” is a blend of the cost of fuel in inventory at the beginning of the year with the cost of fuel purchased during the year. The fuel conversion level was 630 in 2007 test year and decreased to 588 and 607 in 2014 test year and 2015 test year respectively.

The forecast increase in power purchased of $28.3 million and $24.9 million in 2014 and 2015 respectively is primarily the result of energy purchases from wind generation projects in addition to changes in power purchase arrangements related to Exploits Generation. There were also additional costs from Capacity Assistance related to arrangements with Corner Brook Pulp and Paper.

The forecast increase of $33.4 million in 2014 and $47.5 million in 2015 in the other costs category is largely tied to a rise in salary and fringe benefits resulting from an increase to general salaries and hourly rates from collective agreements for unionized and non-unionized employees. According to Hydro, in order to attract and retain a qualified workforce, the company has provided wage and benefit increases over the 2007 to 2015 period, enabling Hydro to be competitive with market.

As noted in the pre-filed evidence on page 3.15, the main reason for the forecast increase in the depreciation expense of $16.4 million in 2014 and $25.0 million in 2015 is reflected in the growth in Hydro’s capital program.

The final component of the 2014 and 2015 test year revenue requirements is interest, which has offset the increase over the 2007 test year by $13 million in 2014 and $13.5 million in 2015. As outlined in the pre-filed evidence on page 3.31, this decrease is primarily due to a reduction of approximately $9.4 million and $8.7 million in debt guarantee fees paid by Hydro in 2014 and 2015 respectively. 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. In 2008, as a means of improving Hydro’s net income, the Government waived Hydro’s requirement to pay this fee while continuing to guarantee Hydro’s debt. This waiver continued until 2011 when the fee was reinstated at a market rate. The Company has noted that the debt guarantee fee is estimated to be $5.3 million lower for test year 2014 and $7.5 million lower for test year 2015 then if it was based on the 2007 methodology (i.e. 1% of outstanding debt).

Comparison of 2014 and 2015 Forecasts to Prior Year’s Actuals

The forecast revenue requirement for 2014 of $562.9 million is $87.7 million higher than 2013 actuals. The forecast revenue requirement for 2015 of $662.5 million is $99.6 million higher than 2014 test year. Details on Hydro’s revenue requirement for 2014 test year and 2015 test year are included in the pre-filed Finance evidence Schedule III, page 1 of 2. Details on Hydro’s actual revenue requirement for 2014 are included in the updated finance schedules found in Hydro’s revision to NP-NLH-307. The following table reproduces a portion of this detail showing a comparison of the 2014 and 2015 forecast to the company’s actual results for 2007 to 2014.

Table 22: Revenue requirement (2007-2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Depreciation	$ 38,342	$ 40,393	$ 41,744	$ 43,790	$ 45,217	$ 46,865
Accretion of asset retirement obligation	-	-	-	-	467	715
Fuel	150,281	149,854	136,933	137,994	131,276	132,003
Power Purchased	38,606	41,388	46,782	44,244	52,221	56,986
Other Costs						
Salaries and fringe benefits	70,171	73,123	76,381	82,517	87,556	90,907
System equip. maint.	23,525	22,282	22,122	21,748	21,512	20,261
Insurance	1,704	1,783	1,937	1,960	1,965	2,109
Transportation	2,776	3,046	3,038	3,056	3,377	3,600
Office supplies	2,262	2,182	2,161	2,100	2,307	2,230
Bldg. rentals and maint.	1,234	1,078	1,145	1,170	1,172	1,027
Professional services	3,865	4,443	3,612	4,215	6,092	7,324
Travel	2,942	2,854	2,910	2,755	2,977	2,979
Equipment rentals	1,081	1,493	1,721	1,738	1,636	1,699
Miscellaneous	4,246	4,359	8,065	3,829	4,736	5,144
Loss on disposal	902	2,580	1,267	687	925	5,396
Write down of assets	-	-	506	-	-	-
Sub-total	114,708	119,223	124,865	125,775	134,255	142,676
Allocations						
Other IOCC	(2,679)	(2,672)	(1,875)	(2,648)	(2,292)	(2,215)
Hydro capitalized	(12,044)	(15,461)	(17,164)	(20,716)	(21,276)	(20,723)
Cost recoveries	(1,390)	(1,815)	(4,190)	(4,748)	(5,198)	(7,874)
Subtotal	(16,113)	(19,948)	(23,229)	(28,112)	(28,766)	(30,812)
Total	98,595	99,275	101,636	97,663	105,489	111,864
Interest	103,242	87,610	83,440	86,766	90,844	89,961
Regulated earnings	2,711	8,874	17,211	6,604	20,599	16,900
Revenue requirement	$ 431,777	$ 427,394	$ 427,746	$ 417,061	$ 446,113	$ 455,294

Table 23: Revenue requirement (2013 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Depreciation	$ 50,832	$ 55,214	$ 55,283	$ 63,792	$ 4,382	$ 69	$ 8,578
Accretion of asset retirement obligation	911	852	852	878	(59)	-	26
Fuel	155,957	201,714	195,160	267,820	45,757	(6,554)	66,106
Fuel supply deferral	-	(9,956)	(9,650)	1,991	(9,956)	306	11,947
Power Purchased	59,379	66,668	63,741	63,254	7,289	(2,927)	(3,414)
Other Costs							
Salaries and fringe benefits (Note 1)	96,431	103,400	106,067	111,542	6,969	2,667	8,142
System equip. maint.	22,005	22,979	28,620	26,825	974	5,641	3,846
Insurance	2,422	2,689	2,579	2,607	267	(110)	(82)
Transportation (Note 2)	3,578	3,832	3,785	3,545	254	(47)	(287)
Office supplies	2,595	2,629	2,392	2,804	34	(237)	175
Bldg. rentals and maint.	1,186	1,149	1,228	1,217	(37)	79	68
Professional services	5,874	12,207	12,629	9,494	6,333	422	(2,713)
Travel	3,338	3,710	3,208	3,717	372	(502)	7
Equipment rentals	1,877	1,877	2,017	3,066	-	140	1,189
Miscellaneous	5,218	6,471	6,681	5,772	1,253	210	(699)
Loss on disposal	3,634	2,068	1,708	4,074	(1,566)	(360)	2,006
Sub-total	148,158	163,011	170,914	174,663	14,853	7,903	11,652
Allocations							
Other IOCC	(1,945)	(1,926)	(1,926)	(1,387)	19	-	539
Hydro capitalized	(21,656)	(23,326)	(24,090)	(23,954)	(1,670)	(764)	(628)
Cost recoveries	(9,111)	(9,623)	(10,900)	(7,069)	(512)	(1,277)	2,554
Subtotal	(32,712)	(34,875)	(36,916)	(32,410)	(2,163)	(2,041)	2,465
Total	115,446	128,136	133,998	142,253	12,690	5,862	14,117
Interest (Note 3)	92,394	89,723	90,051	89,255	(2,671)	328	(468)
Regulated earnings	209	30,504	17,661	33,232	30,295	(12,843)	2,728
Revenue requirement	$ 475,128	$ 562,855	$ 547,096	$ 662,475	$ 87,727	$ (15,759)	$ 99,620

		Forecast 2014	Actuals 2014	Forecast 2015
Note 1:	Salaries and fringe benefits per table	$103,400	$106,067	$111,542
	Less: capitalized salaries included in allocations	(21,944)	(22,613)	(22,654)
	Salaries and fringe benefits per Schedule III, P. 1 of 2	$81,456	$83,454	$88,888
Note 2:	Transportation per table	$3,832	$3,785	$3,545
	Less: amount included in allocations	(1,382)	(1,477)	(1,300)
	Transportation per Schedule III, P. 1 of 2	$2,450	$2,308	$2,245
Note 3:	Interest per table	$89,723	$90,051	$89,255
	Regulated earnings per table	30,504	17,661	33,232
	Add: cost of service exclusions per Schedule III, P. 1 of 2	336	1,426	323
	Return on rate base per Schedule III, P. 1 of 2	$120,563	$109,138	$122,810

Based on the information in this summary, the most significant increase, which represents approximately $45.8 million or 52% of the total increase in the 2014 test year revenue requirement over 2013 and approximately $66.1 million or 66% of the total increase in the 2015 revenue requirement over 2014 test year, is the cost of fuel. The cost of fuel is discussed in more detail later in this report.

Regulated earnings are another component of the 2014 revenue requirement forecast to increase significantly in comparison to 2013. The requested rate of return on equity of 8.80% for the 2014 test year is significantly higher than the 0.06% earned in 2013 and represents an increase of $30.3 million in this component of the revenue requirement.

The table below provides an analysis of the breakdown of the cost of energy on the basis of the number of kWhs sold for the years 2007 to 2014, and the forecast for 2014 and 2015.

Table 24: Total cost of energy and cost per kWh

Year	kWh sold and used	Depreciation	Fuel	Fuel Supply Deferral	Purchased Power	Other Costs	Interest	Accretion	Regulated Earnings	Total Cost of Energy	Cost per kWh
2007	6,771,000	38,342	150,281	-	38,606	98,595	103,242	-	2,711	431,777	0.0638
2008	6,667,000	40,393	149,854	-	41,388	99,275	87,610	-	8,874	427,394	0.0641
2009	6,450,000	41,744	136,933	-	46,782	101,636	83,440	-	17,211	427,746	0.0663
2010	6,327,000	43,790	137,994	-	44,244	97,663	86,766	-	6,604	417,061	0.0659
2011	6,629,000	45,217	131,276	-	52,221	105,489	90,844	467	20,599	446,113	0.0673
2012	6,782,000	46,865	132,003	-	56,986	111,864	89,961	715	16,900	455,294	0.0671
2013	6,974,000	50,832	155,957	-	59,379	115,446	92,394	911	209	475,128	0.0681
2014F	7,503,000	55,214	201,714	(9,956)	66,668	128,136	89,723	852	30,504	562,855	0.0750
2014	7,333,000	55,283	195,160	(9,650)	63,741	133,998	90,051	852	17,661	547,096	0.0746
2015F	7,709,000	63,792	267,820	1,991	63,254	142,253	89,255	878	33,232	662,475	0.0859

Note 1: In annual reviews prior to 2013, kWh sold and used included sales to Iron Ore Company of Canada (IOCC). However, since IOCC is a non-regulated customer, those sales have been removed in this table.

As shown, the cost of energy per kWh in the 2014 cost of service is forecast to increase by 10.1% over what was experienced in 2013, and 17.6% over what was experienced in 2007. The cost of energy per kWh in the 2015 cost of service is forecast to increase by 14.5% over the forecast for 2014, and 34.6% over what was experienced in 2007. The actual cost per kWh in 2014 was 0.5% less than forecast.

Additional analysis of the 2014 and 2015 revenue requirement in comparison to actual results experienced by Hydro over the last several years are included in the following sections of our report.

Depreciation

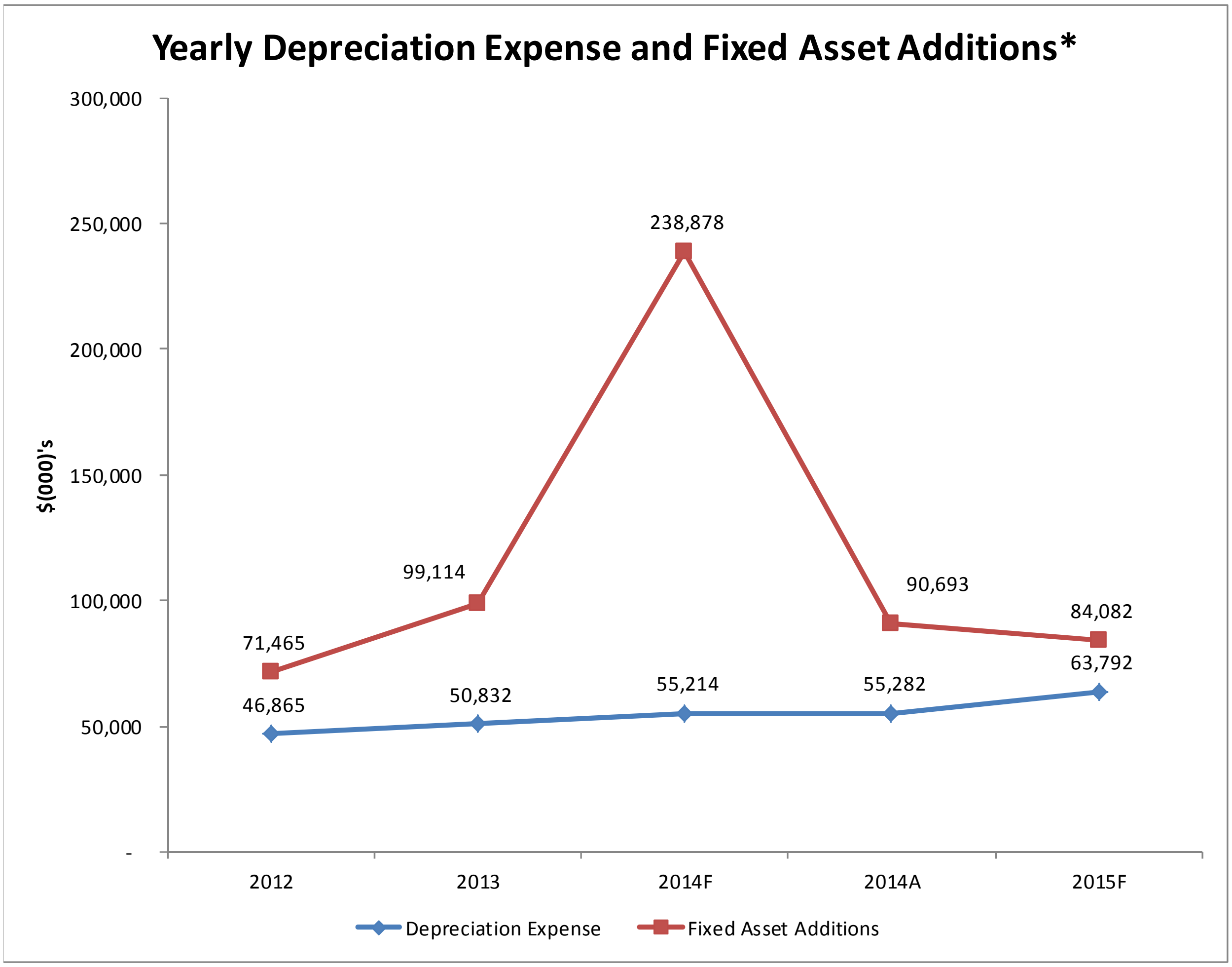
Our procedures with respect to depreciation were focused on reviewing the rates of depreciation incorporated in the 2014 and 2015 forecast to ensure compliance with the Gannett Fleming Depreciation Study dated November 2012 and compliance with Board Order P.U. 40 (2012). In addition, our procedures included reconciling the detailed depreciation schedule to the pre-filed evidence, agreeing the useful life of a sample of assets from Hydro's asset records to the Gannett Fleming depreciation study, and recalculating the depreciation for the assets in our sample.

Hydro has forecast amortization expense of $55.2 million in 2014 and $63.8 in 2015 compared to an actual 2014 expense of $55.3 million, in accordance with the depreciation methodology approved in P.U. 40 (2012). A comparison of the actual depreciation expense from 2012 to 2014, as well as forecast for 2014 and 2015, is detailed in the following table. The table also calculates depreciation costs as a percentage of cost.

Table 25: Depreciation as a percentage of cost (2012 – 2014 and test years 2014 & 2015)

(000)'s	Actuals 2012	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Depreciation	46,865	50,832	55,214	55,283	63,792	4,382	69	8,578
Cost	1,510,588	1,603,351	1,840,320	1,693,531	1,921,632	236,969	(146,789)	81,312
% of cost	3.10%	3.17%	3.00%	3.26%	3.32%	-0.17%	0.26%	0.32%
Change in % over prior year	-0.16%	0.07%	-0.17%	0.09%	0.32%			
Change in depreciation	1,648	3,967	4,382	4,451	8,578			

Graph 3: Annual depreciation expense and fixed asset additions



*Fixed asset additions is comprised of Additions to Plant in Service, net of Contributions in Aid of Construction, as detailed in Hydro's response to CA-NLH-116. with the exception of 2014 actual, which was provided to us directly by Hydro.

The above table and graph show that although the cost was lower in 2014 than forecast by $146.8 million, depreciation between the two years remained relatively consistent. This is partially due to the impact of the costs associated with the 100 MW Holyrood Combustion Turbine (CT), which was forecast to be included in the cost for the 2014 test year, with approximately one month's depreciation to be recorded as it was forecast to be put in service late in 2014. However, the CT was not put in service in 2014 and accordingly is not reflected in the 2014 actual cost or depreciation. The following table removes the effect of the CT for 2014 and the 2014 test year:

Table 26: Combustion Turbine Impact for 2014 & 2014 Test Year

	Cost	CT Forecast	Adjusted Cost	Depreciation	CT Forecast	Adjusted Depreciation	Adjusted % of Cost
Actuals 2014	1,693,531	-	1,693,531	55,283	-	55,283	3.26%
Forecast 2014	1,840,320	(109,677)	1,730,643	55,214	(262)	54,952	3.18%
Variance	(146,789)	(109,677)	(37,112)	69	262	331	0.09%

The adjusted percentage of cost for 2014 forecast is 3.18%, which is consistent with the depreciation as a percentage of cost for 2013 of 3.17%. The adjusted percentage of cost for 2014 actual is 3.26%, which is higher than both 2013 and 2014 forecast. According to Hydro, the remaining difference is due to projects that were forecast to go into service in 2014 but instead were carried over to 2015 and under spending on various projects due to lower costs being incurred. While there were $146.8 million in assets not put into service, the forecast depreciation on these assets for the 2014 test year was only $0.4 million. Hydro further stated that the "reduction in depreciation was off-set by assets that went into service earlier in the year and/or had lower service lives than originally budgeted."

Depreciation expense for test year 2015 is forecast to be $8.6 million higher than 2014 forecast. This increase in depreciation expense reflects the forecast test year 2015 capital additions of approximately $84.1 million and the full year impact of 2014 forecast capital additions. In addition, assets which relate to the Holyrood Thermal Generating Station are being amortized on a straight-line basis until the year 2020, when the plant will be decommissioned.

As a result of completing our procedures, no significant discrepancies in the calculation of the 2014 or 2015 test year forecasts were noted.

Fuel Costs

Fuel expense for the 2015 test year of $267.8 million is forecast to increase by approximately $66.1 million over 2014 forecast. The various fluctuations within the fuel cost category have been noted below for the years 2007 to 2013, as well as the 2014 and 2015 forecast and actual 2014:

Table 27: Fuel costs by category (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
No.6 Fuel	107,369	123,734	80,585	100,674	135,136	164,001
Fuel Additives	100	109	89	178	126	44
Fuel Costs Indirect	83	57	69	63	61	75
Environmental Handling Fee	5	46	10	28	12	24
Ignition Fuel	298	323	244	296	389	389
Gas Turbine Fuel	399	1,515	1,015	1,197	395	877
Diesel Fuel Rural	10,486	15,005	12,631	12,224	16,013	15,927
Rate Stabilization Plan (RSP)	31,541	9,065	42,290	23,334	(20,856)	(49,334)
	150,281	149,854	136,933	137,994	131,276	132,003

Table 28: Fuel costs by category (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
No.6 Fuel	171,786	255,842	244,342	244,914	84,056	(11,500)	(10,928)
Fuel Additives	13	17	28	-	4	11	(17)
Fuel Costs Indirect	380	205	142	196	(175)	(63)	(9)
Environmental Handling Fee	16	26	24	69	10	(2)	43
Ignition Fuel	495	378	516	248	(117)	138	(130)
Gas Turbine Fuel	1,427	6,465	6,910	3,673	5,038	445	(2,792)
Diesel Fuel Rural	17,155	20,659	19,358	18,754	3,504	(1,301)	(1,905)
Rate Stabilization Plan (RSP)	(35,315)	(81,878)	(76,160)	(34)	(46,563)	5,718	81,844
	155,957	201,714	195,160	267,820	45,757	(6,554)	66,106

Actual fuel costs for 2014 are $6.6 million lower than the amount forecast. This variance is primarily due to lower costs relating to No.6 fuel. Actual No. 6 Fuel costs for 2014 decreased by $11.5 million compared to the 2014 test year. This decrease is primarily due to a decrease in the number of barrels consumed during the year. The actual number of barrels used in 2014 was 83,821 lower than the number of barrels forecast in test year; this was primarily due to 57.7 fewer GWh of generation from the Holyrood Thermal Generation Plant than 2014 forecast. Also, the actual average price of fuel per barrel fell from $109.59 in test year to $108.54 in actual 2014.

Significant fuel costs for test year 2014 and 2015 are discussed in further detail below.

No.6 Fuel

According to Schedule V of Section 2 of the pre-filed evidence, Hydro is forecasting the consumption of 2,334,546 barrels of No. 6 fuel in order to produce 1,373 GWh of thermal power at Holyrood in 2014. This is an increase of 415.6 GWh and 723,580 barrels of fuel over 2013. For 2015 Hydro is forecasting the consumption of 2,624,371 barrels of No. 6 fuel in order to produce 1,593 GWh of thermal power at Holyrood. This is an increase of 220 GWh and 289,825 barrels of fuel over 2014 test year. The forecast of No.6 fuel expense takes into account a number of factors including: the price of fuel; the estimated energy to be generated using thermal production at Holyrood; and the fuel conversion factor (i.e. the number of kWh generated per barrel of No.6 fuel). The impact of each of these factors relating to the 2014 test year revenue requirement compared to 2013 and the 2015 test year revenue requirement compared to the 2014 test year is summarized below:

	2013 vs. 2014F ($000,000)	2014F vs. 2015F ($000,000)
Increase/decrease in the price of No.6 fuel/bbl	$ 6.9	$ (42.7)
Change in conversion factor	2.5	(9.3)
Increase in thermal production	74.6	41.0
Net increase in No.6 fuel expense	$ 84.0	$ (11.0)

<u>Price per barrel:</u>

In its current Application, Hydro is forecasting an average market price of $106.46 per barrel for 2014. However, when the 2014 opening value of fuel inventory is taken into consideration, the consumption price per barrel of No.6 fuel is $109.59 for 2014 compared to $106.64 for 2013. For 2015 Hydro is forecasting an average market price of $90.85 per barrel. Hydro has obtained this forecast information from the PIRA Energy Group, based on price forecasts for September 2014. Since this date oil prices have decreased significantly, which would impact the revenue requirement. However, when the 2015 opening value of fuel inventory is taken into consideration, the consumption price per barrel of No.6 fuel is $93.32 for 2015 compared to $109.59 for 2014 test year. The prices used by Hydro are derived by applying Hydro's contract discount to PIRA's New York Harbour price forecast and by applying a forecast for exchange. The forecast prices also assume fuel contains 0.7% sulphur content.

To calculate the incremental change in fuel cost associated with the price per barrel of fuel, Hydro used the forecast barrels of fuel to be consumed per the 2014 test year and multiplied it by the price of fuel forecast for 2014 and actual cost of fuel for 2013. Hydro did the same for 2015 by multiplying the forecast barrels of fuel to be consumed per the 2015 test year by the price of fuel forecast for 2015 and the price of fuel forecast for 2014.

Number of barrels of No.6 fuel to be consumed in 2014:				2,334,546
Average fuel price for barrels forecast to be consumed for 2014 ($000)	$	109.59	/bbl	$ 255,843
Average fuel price for barrels consumed in 2013 ($000)	$	106.64	/bbl	$ 248,956
Increase in fuel cost relating to fuel price per barrel				$ 6,887

Number of barrels of No.6 fuel to be consumed in 2015:				2,624,371
Average fuel price for barrels forecast to be consumed for 2015 ($000)	$	93.32	/bbl	$ 244,906
Average fuel price for barrels to be consumed in 2014 ($000)	$	109.59	/bbl	$ 287,605
Decrease in fuel cost relating to fuel price per barrel				$ (42,699)

Fuel Conversion Factor

Hydro is forecasting a conversion factor of 607 kWh/barrel in the 2015 test year. The forecast conversion factor for 2014 test year was 588 kWh/barrel and the conversion factor for 2013 was 594 kWh/barrel. The decline in 2014 was due to lower production requirements as a result of reduced load and higher energy purchases that year. The increase in the factor for 2015 test year means fewer barrels of fuel will be required to generate the same amount of energy. Per page 2.75 of the pre-filed evidence, the conversion factor is forecast to improve in 2015 due to higher production requirements and higher average unit output levels.

To calculate the impact that this change has on the revenue requirement for 2014 test year in comparison to 2013, Hydro used the forecast net production of thermal energy in 2014, calculated the difference in the number of barrels of fuel that would be required for each conversion factor and multiplied the result by the price of fuel consumed for 2013. Hydro used the same process to calculate the impact for 2015 test year in comparison to 2014 test year by using the forecast net production of thermal energy in 2015, calculating the difference in the number of barrels of fuel that would be required for each conversion factor and then multiplying the result by the price of fuel consumed for 2014.

Net thermal production forecast for 2014:	1,373.00	GWh
Number of barrels @ 588 kWh per barrel	2,335,034	
Number of barrels @ 594 kWh per barrel	2,311,448	
Increase in number of barrels	23,586	
Average price per barrel consumed for 2013	$ 106.64	
Increase in fuel cost relating to conversion factor ($000)	$ 2,515	

Net thermal production forecast for 2015:	1,593.00	GWh
Number of barrels @ 607 kWh per barrel	2,624,382	
Number of barrels @ 588 kWh per barrel	2,709,184	
Decrease in number of barrels	(84,801)	
Average price per barrel to be consumed for 2014	$ 109.59	
Decrease in fuel cost relating to conversion factor ($000)	$ (9,293)	

As highlighted above, in 2014 the decrease in the conversion factor increases the number of barrels required in the production of thermal energy and in turn increases the fuel expense. The opposite occurred in 2015 as the increase in the conversion factor decreases the number of barrels required in the production of thermal energy and in turn decreases the fuel expense.

Net Thermal Production

Thermal production in 2014 is forecast to increase by 415.6 GWh in comparison to 2013. To calculate the impact that the change in hydraulic production has on the revenue requirement for 2014 in comparison to 2013, Hydro used the difference in forecast net production of thermal energy between 2013 and 2014, and calculated the increase in the number of barrels of fuel that would be required using the 2013 conversion factor of 594 kWh/barrel. Hydro did the same thing to calculate the impact that the change in hydraulic production has on the revenue requirement for 2015 in comparison to 2014 test year by using the difference in forecast net production of thermal energy between 2014 and 2015, and calculating the increase in the number of barrels of fuel that would be required using the 2014 conversion factor of 588 kWh/barrel.

Net thermal production forecasted for 2014	1,373.00	GWh
Net thermal production for 2013	957.40	GWh
Net increase in thermal production	415.60	GWh
Increase in barrels required @ 594 kWh per barrel	699,663	
Average price per barrel consumed in 2013	$ 106.64	
Increase in fuel cost relating to increased thermal production ($000)	$ 74,612	

Net thermal production forecasted for 2015	1,593.00	GWh
Net thermal production forecast for 2014	1,373.00	GWh
Net increase in thermal production	220.00	GWh
Increase in barrels required @ 588 kWh per barrel	374,150	
Average price per barrel to be consumed in 2014	$ 109.59	
Increase in fuel cost relating to increased thermal production ($000)	$ 41,003	

Gas Turbine Fuel

Gas turbine fuel costs are forecast to increase by $5.0 million in 2014 test year over 2013. According to Hydro, this is due to higher production requirements and fuel usage from the Holyrood gas turbine, Hardwood's gas turbine and Stephenville's gas turbine.

Costs for the Holyrood gas turbine are associated with the operation of Newfoundland Power's mobile generator which was relocated to Holyrood and installed on December 30, 2013 and has since been removed. From January to March 2014 this unit was used for system peaking requirements due to capacity issues on the system resulting from the generation supply problems and high customer demands.

Higher production requirements for the Hardwood gas turbine and Stephenville's gas turbine was due to their increased use from January to March 2014 for system peaking requirements and storm preparedness due to capacity issues on the system resulting from the generation supply problems and high customer demands. This resulted in an increase in average fuel consumption in 2014 test year relative to 2013.

Gas turbine fuel costs are forecast to decrease by $2.8 million in 2015 compared to 2014 forecasts. According to Hydro, this is due to lower production requirements and fuel usage for Hardwood's gas turbine, Stephenville's gas turbine and NF Power's gas turbine, offset by higher production requirements and fuel usages for the Holyrood gas turbine.

In 2015, costs for the Holyrood gas turbine are associated with operation of the new Holyrood combustion turbine unit and are based on requirements for testing weather preparedness and to maintain spinning reserves on the Island Interconnected system. These higher costs are offset by a lower average fuel consumption price. Costs for the Hardwood gas turbine and the Stephenville gas turbine in 2015 are also associated with operation of the new Holyrood combustion turbine unit and are based on requirements for testing weather preparedness and to maintain spinning reserves on the Island Interconnected system. However, they are forecast to experience lower costs that are offset by a higher average fuel consumption.

There are no production requirements for Newfoundland Power's standby units in the 2015 forecast.

Diesel Fuel Rural

The following table provides a breakdown of actual and forecast energy requirements for the isolated systems as per Schedule IV in the pre-filed evidence.

Table 29: Energy requirements - Isolated systems

Diesel Fuel Rural	2007 MWh	2008 MWh	2009 MWh	2010 MWh	2011 MWh	2012 MWh	2013 MWh	2014F MWh	2014A MWh	2015F MWh
Labrador Isolated										
L'Anse au Loup	17,556	18,495	20,363	20,912	23,292	22,049	24,073	24,661	25,859	24,953
Others	35,340	36,421	37,644	37,296	38,754	38,207	39,504	44,316	41,330	44,911
Subtotal	52,896	54,916	58,007	58,208	62,046	60,256	63,577	68,977	67,189	69,864
Island Isolated	8,043	8,707	8,934	7,528	7,876	7,621	7,797	7,679	7,707	7,645
Total	60,939	63,623	66,941	65,736	69,922	67,877	71,374	76,656	74,896	77,509
Year over year change %		4.40%	5.22%	-1.80%	6.37%	-2.92%	5.15%	7.40%	-2.30%	3.49%

Diesel fuel costs for 2014 were forecast to increase by $3.5 million over 2013 actuals. According to Hydro, this is primarily due to the increase in costs for Labrador Isolated. $2.6 million of the $3.5 million variance is due to higher forecasted production for 2014 associated with load growth for Labrador Isolated. Higher forecasted diesel fuel prices also contributed to the variance. Production is forecast to decrease for Island Isolated and L'anse au Loup in 2015 compared to the 2014 test year. However, these decreases are partially offset by higher diesel fuel prices.

Actual diesel fuel costs for 2014 are $1.3 million lower than the amount forecast. According to Hydro, this is primarily due to variances in production requirements in St. Anthony, Labrador Isolated and L'anse au Loup. For St. Anthony, actual production requirements were higher than forecast. For Labrador Isolated, actual production and fuel costs were lower than forecasted. For L'anse au Loup, actual production was higher than forecast and was partially offset by a lower fuel cost.

Diesel fuel costs for 2015 are forecast to decrease by $1.9 million over the 2014 test year. According to Hydro, this is primarily due to lower forecast production requirements and fuel costs for St. Anthony, Hawkes Bay and Island Isolated. The St. Anthony and Hawkes Bay plants were used for system peaking requirements from January to March in 2014 due to capacity issues resulting from generation supply problems and high customer demand. For 2015, costs are associated with operation based on requirements for testing and weather preparedness. Production is forecast to increase for Labrador Isolated and L'anse au Loup in 2015. However, this increase is partially offset by a lower cost of fuel.

Fuel Supply deferral

Hydro is proposing the deferral of $9,956,000 in fuel supply costs in the 2014 test year. Additional comments on this deferral are discussed in the Deferred Accounts section of this report.

Power purchased

The Company's power purchased cost for 2015 is expected to be $63.3 million, which represents a decrease of $3.4 million over the 2014 forecast, is largely due to a decrease in the costs of power purchased from the Corner Brook Pulp & Paper Curtailable.

Actual power purchased costs for 2014 are $2.9 million lower than the amount forecast. This variance is primarily due to the decrease in NUGs and L'Anse au Loup costs, partially offset by the increase in costs relating to Capacity Expansion. These variances are discussed in further detail below.

The breakdown of power purchased by category is as follows:

Table 30: Power purchased costs by category (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Energy Costs - NUGS	31,177	34,362	41,673	38,831	46,127	50,368
Demand & energy - CF(L)Co	2,205	2,428	2,019	2,237	1,914	2,024
L'Anse au Loup	1,586	2,255	1,644	2,054	2,890	2,931
Island wheeling	492	607	556	591	601	646
Secondary energy	2,294	1,364	444	(74)	-	321
Capacity Expansion	761	265	352	491	581	400
Ramea Wind	60	101	94	114	108	162
CF(L)Co Interest	31	6	-	-	-	-
Ramea Hydrogen	-	-	-	-	-	134
	38,606	41,388	46,782	44,244	52,221	56,986

Table 31: Power purchased costs by category (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Energy Costs - NUGS	52,944	53,471	50,694	55,294	527	(2,777)	1,823
Demand & energy - CF(L)Co	2,116	2,113	1,996	1,857	(3)	(117)	(256)
CBPP & Vale Capacity Assistance	-	6,126	6,225	2,122	6,126	99	(4,004)
L'Anse au Loup	3,056	3,329	3,102	3,055	273	(227)	(274)
Island wheeling	676	696	695	693	20	(1)	(3)
Secondary energy	160	-	-	-	(160)	-	-
Capacity Expansion	206	712	812	-	506	100	(712)
Ramea Wind	188	178	191	174	(10)	13	(4)
Ramea Hydrogen	33	43	26	59	10	(17)	16
	59,379	66,668	63,741	63,254	7,289	(2,927)	(3,414)

NUGS

According to the table above, energy purchases from NUGs accounts for approximately 80% of the total forecast power purchased cost for 2014 and approximately 87% of the total forecast power purchased cost for 2015. The cost of power purchased from the NUGs continues to increase each year. In 2007 the costs totalled $31.2 million, and have increased to $53.5 million in 2014 test year. For the 2015 forecast, increases in costs are anticipated due to an increase in the number of GWhs of power expected to be purchased for the year. The following table provides a breakdown of the six main non-utility generators which supply Hydro with power to service the Island Interconnected system for 2010 to forecast 2015. The data for this table was compiled from Regulated Activities Schedule VI in the pre-filed evidence.

Table 32: Non-utility generators – Island Interconnected (2010 - 2013 and test years 2014 and 2015)

	2010			2011		
	GWh	$ ('000s)	Avg cost per GWh	GWh	$ ('000s)	Avg cost per GWh
Star Lake	135.83	$ 11,232	$ 82,692	129.82	$ 5,193	$ 40,002
Rattle Brook	17.42	1,380	79,219	18.66	1,490	79,850
Corner Brook Cogen	51.54	5,469	106,112	50.5	5,917	117,168
Exploits River Project	112.40	8,664	77,082	-	-	-
St. Lawrence Wind (net of incentive credit)	100.46	6,451	64,215	110	7,091	64,464
Fermeuse Wind (net of incentive credit)	82.80	5,635	68,056	87.96	6,011	68,338
Nalcor Grand Falls, Bishops Falls and Buchans	-	-	-	510.63	20,425	40,000
Total Energy Costs - NUGs	500.45	$ 38,831	$ 77,592	907.57	$ 46,127	$ 50,825

	2012			2013		
	GWh	$ ('000s)	Avg cost per GWh	GWh	$ ('000s)	Avg cost per GWh
Star Lake	144.45	$ 5,778	$ 40,000	140.61	$ 5,624	$ 39,997
Rattle Brook	14.63	1,181	80,725	14.76	1,229	83,266
Corner Brook Cogen	47.84	6,906	144,356	55.89	9,260	165,683
St. Lawrence Wind (net of incentive credit)	103.84	6,797	65,456	96.38	6,244	64,785
Fermeuse Wind (net of incentive credit)	91.20	6,270	68,750	95.52	6,598	69,075
Nalcor Grand Falls, Bishops Falls and Buchans	585.90	23,436	40,000	599.73	23,989	40,000
Total Energy Costs - NUGs	987.86	$ 50,368	$ 50,987	1,002.89	$ 52,944	$ 52,791

	2014F			2015F		
	GWh	$ ('000s)	Avg cost per GWh	GWh	$ ('000s)	Avg cost per GWh
Star Lake	144.99	$ 5,892	$ 40,637	142.18	$ 5,687	$ 39,999
Rattle Brook	13.70	1,127	82,263	15.00	1,254	83,600
Corner Brook Cogen	48.93	9,805	200,388	51.07	10,281	201,312
St. Lawrence Wind (net of incentive credit)	99.54	6,529	65,592	104.80	6,876	65,611
Fermeuse Wind (net of incentive credit)	81.72	5,734	70,166	84.41	5,856	69,376
Nalcor Grand Falls, Bishops Falls and Buchans	611.94	24,384	39,847	633.50	25,340	40,000
Total Energy Costs - NUGs	1,000.82	$ 53,471	$ 53,427	1,030.96	$ 55,294	$ 53,634

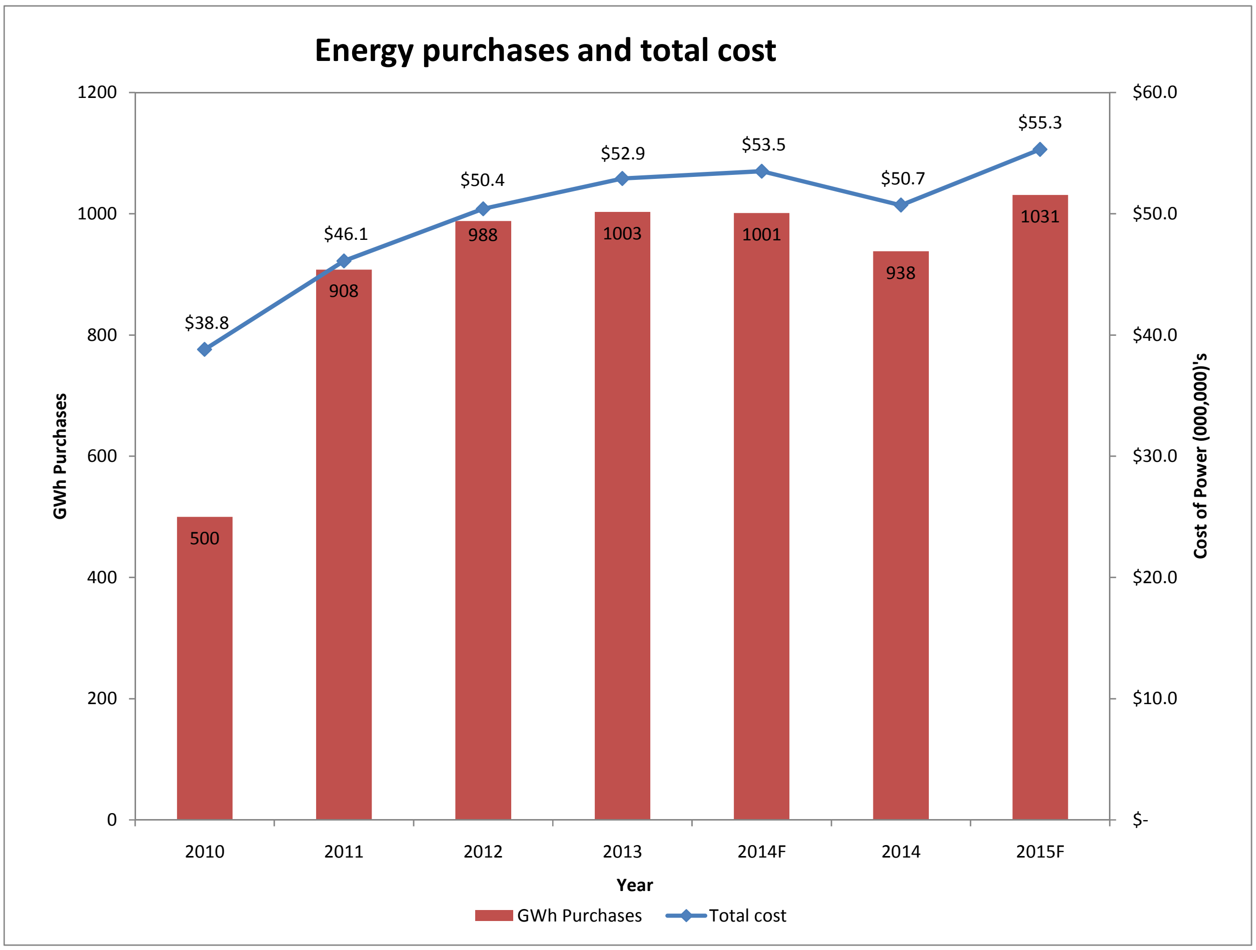
The energy purchase rate for production at the Nalcor Exploits Facilities was expected to remain constant at approximately 4 cents/kWh in 2014 and 2015 test years and did remain at this rate for 2014 actual.

The following table provides a comparison of the 2014 test year purchases to the company's actual results for 2014.

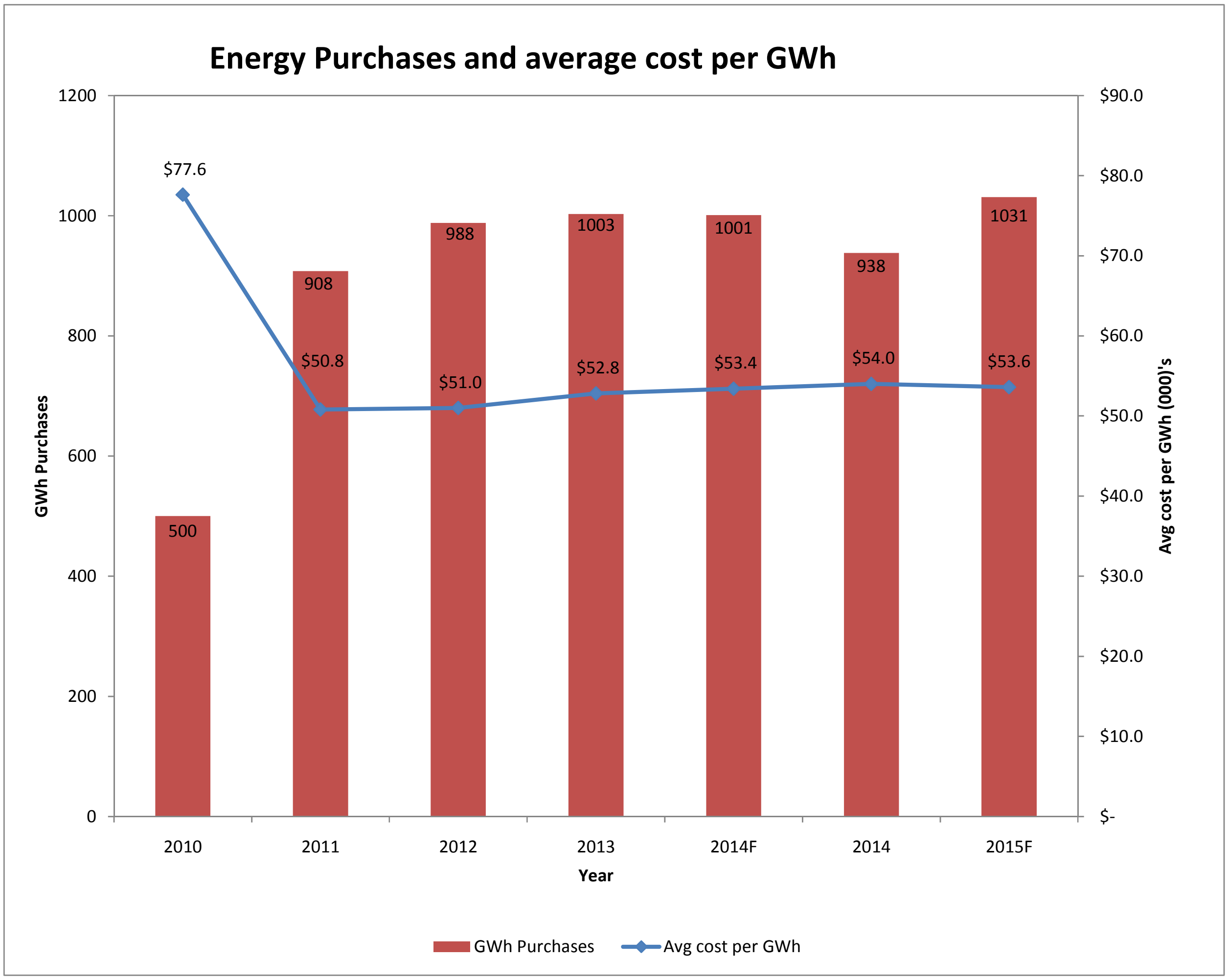
Table 33: Non-utility generators – Island Interconnected (2014 test year and 2014 actual)

	2014F			2014		
	GWh	$ ('000s)	Avg cost per GWh	GWh	$ ('000s)	Avg cost per GWh
Star Lake	144.99	$ 5,892	$ 40,637	122.39	$ 4,895	$ 39,995
Rattle Brook	13.70	1,127	82,263	13.10	1,101	84,046
Corner Brook Cogen	48.93	9,805	200,388	48.29	9,660	200,041
St. Lawrence Wind (net of incentive credit)	99.54	6,529	65,592	97.54	6,414	65,758
Fermeuse Wind (net of incentive credit)	81.72	5,734	70,166	80.58	5,576	69,198
Nalcor Grand Falls, Bishops Falls and Buchans	611.94	24,384	39,847	576.21	23,048	39,999
Total Energy Costs - NUGs	1,000.82	$ 53,471	$ 53,427	938.11	$ 50,694	$ 54,038

Graph 4: Energy purchases and total cost



Graph 5: Energy purchases and average cost per GWh



According to page 2.73 of the pre-filed evidence, the forecast for 2015 is based on Hydro's hydraulic generation model (VISTA) output for the Exploits Generation, the historical average data for the Rattle Brook and design estimates for the wind farms. As indicated in the table, the number of GWh to be purchased from NUGs is decreasing and the average price per GWh is increasing in the 2014 forecast in comparison to the 2013 actual results. For 2015, the number of GWh to be purchased from NUGS is increasing and the average price per GWh is also increasing in comparison to 2014 forecasts.

<u>L'anse au Loup</u>

The costs for L'Anse au Loup are forecast to increase by $273,000 in 2014 over 2013. According to Hydro, this is due to an increase of power purchases from HQ linked to load growth and reduced outages, and a higher average cost of energy purchases due to higher forecasted fuel prices. The costs for L'Anse au Loup are forecast to decrease by $274,000 in 2015 over 2014 forecasts. This is due to an increase in energy purchases from HQ resulting from system load growth and reduced maintenance interruptions that is offset by a decrease in the average cost of energy purchases as a result of lower forecasted fuel prices.

Capacity Expansion

The costs for Capacity Expansion are forecast to increase by $506,000 in 2014 over 2013. According to Hydro, this is due to the extraordinary expense costs which vary from year to year based on the level of expenditure set out in the annual TwinCo plan. Capacity Expansion costs are forecast to decrease by $712,000 in 2015 over 2014 forecasts. This is because Hydro did not budget for capacity expansion costs in 2015. The reason for this is because at the end of 2014 the TwinCo arrangements expired and, as such, no costs related to the Wabush Terminal Station are included in Hydro's Labrador Interconnected System power purchase costs for 2015. The costs for this equipment will be part of the station costs as outlined in section 2.2.5 of the amended application.

Secondary Energy

The costs for secondary energy have not been forecast for the 2014 and 2015 test year due to the inconsistent nature and variability of the reservoir storage requirements.

Actual power purchase 2014 costs were $2.9 million lower than the amount forecast. A major portion of this decrease was a $2.8 million decrease related to NUGS. According to Hydro, this variance is primarily due to lower energy production from the generating unit for Nalcor Exploits and Star Lake, as well as overall lower energy production from the wind turbines. Production was reduced from Nalcor Exploits due to maintenance activities, forced equipment issues and a reduction in Exploits River flows. Production was reduced from Star Lake due to equipment issues, the main issue being with the automatic voltage regulator. Production from the wind turbines was reduced primarily due to diminished winds and maintenance activities in August and September. A reduction in actual costs for L'Anse au Loup of $227,000 compared to the 2014 forecast also contributed to the overall decrease of power purchased costs. According to Hydro, this decrease was due to higher than expected maintenance outages by HQ and lower fuel prices in 2014 than had been forecast.

Interest

Interest expense for 2014 is forecast to decrease by $2.6 million overall compared to the 2013 year. Interest expense for 2015 is forecast to decrease by $0.4 million overall compared to the 2014 forecast. The following is a summary of forecast interest expense for 2014 and 2015 as compared to actuals for 2007 to 2014:

Table 34: Interest expense (2007 – 2012)

(millions)	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Gross interest	102.3	98.2	91.0	90.9	91.1	91.4
Debt guarantee fee	13.1	-	-	-	3.9	3.7
RSP	1.1	2.8	7.0	10.2	12.2	13.2
Amortization of debt discount and financing costs	0.7	0.5	0.4	0.4	0.5	0.5
Amortizaton of foreign exchange losses	2.2	2.2	2.2	2.2	2.2	2.2
Interest on cash borrowed from non-regulated activities	5.0	9.0	-	-	-	-
	124.4	112.7	100.6	103.7	109.9	111.0
Less:						
Interest earned	14.0	15.4	16.4	16.0	17.6	18.3
Interest attributable to CF(L)Co share purchase	0.9	-	-	-	-	-
Interest capitalized during construction	6.3	9.6	0.8	1.0	1.5	2.7
	21.2	25.0	17.2	17.0	19.1	21.0
	103.2	87.7	83.4	86.7	90.8	90.0

Table 35: Interest expense (2013 – 2014 and test years 2014 and 2015)

(millions)	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Gross interest	90.8	87.4	86.6	94.3	(3.4)	(0.8)	6.9
Debt guarantee fee	3.7	3.7	3.7	4.4	-	-	0.7
RSP	17.1	18.2	18.0	12.4	1.1	(0.2)	(5.8)
Amortization of debt discount and financing costs	0.5	0.5	0.5	0.5	-	-	-
Amortizaton of foreign exchange losses	2.2	2.1	2.1	2.2	(0.1)	-	0.1
	114.3	111.9	110.9	113.8	(2.4)	(1.0)	1.9
Less:							
Interest earned	19.8	16.2	16.2	13.6	(3.6)	-	(2.6)
Interest capitalized during construction	2.2	6.0	4.7	10.9	3.8	(1.3)	4.9
	22.0	22.2	20.9	24.5	0.2	(1.3)	2.3
	92.3	89.7	90.0	89.3	(2.6)	0.3	(0.4)

The most significant item impacting net interest in 2015 is the forecast increase of 6.9 million in gross interest. This increase is due to an increase in long-term interest of $9.0 million, offset by a decrease of $2.1 million to the forecast for short-term interest. The increase in long-term interest is driven by higher interest on new forecasted 2015 borrowings ($10.8M) and a full year's interest on the Series AF debentures issued in September 2014 ($5.1M), partially offset by interest savings on the Series V debentures ($6.6M), which matured in 2014. The decrease to the forecast for short-term interest is due to the cash on hand following the forecast $400 million bond issue in March 2015, which results in lower average short-term borrowing requirements throughout the year.

The RSP interest cost is forecasted to decrease by $5.8 million in 2015 compared to 2014. This decrease is due to lower RSP balances and lower interest rates in 2015 test year compared to 2014 test year. The reduction in the RSP balance was primarily related to the $45.9 million 2014 revenue deficiency that was deferred and proposed to be recovered in the 2014 RSP. In P.U. 58 (2014) the Board denied Hydro's proposal of recovery in the 2014 RSP.

The amount of interest earned is forecast to decrease by $3.6 million in 2014 compared to 2013 and is forecast to decrease by $2.6 million in 2015 compared to 2014 test year. The primary reason for these decreases is due to the forecast annual interest on sinking funds decreasing in 2014 and 2015. This is due to 12 months of 2013 and 6 months of 2014 containing interest income for the Series V Sinking Fund, which matured on June 5, 2014.

The amount of interest capitalized during construction is forecast to increase in 2014 by $3.8 million compared to 2013. The amount of interest capitalized during construction is forecast to increase in 2015 by $4.9 million compared to the 2014 forecast. The total interest capitalized during construction is driven by the amount of capital expenditures which is also forecast to increase during that same time period.

Other Costs

Finance Schedule I, page 9 of 11 of the pre-filed evidence, contains details of Hydro's "other costs" forecast for 2014 and 2015 with comparative data from 2007 to 2014. Earlier in our report we provided a table which provides a breakdown of all the cost components which make up the revenue requirement including the "other costs" category. The following tables provide a comparison of the 2014 and 2015 forecasts to actuals from 2007 to 2014, broken down into the various accounts which form the "other costs" category.

Table 36: Other costs by category (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Other costs						
Salaries and fringe benefits	70,171	73,123	76,381	82,517	87,556	90,907
System equip. maint.	23,525	22,282	22,122	21,748	21,512	20,261
Insurance	1,703	1,783	1,937	1,960	1,965	2,109
Transportation	2,776	3,046	3,038	3,056	3,377	3,600
Office Supplies	2,262	2,182	2,161	2,100	2,307	2,230
Bldg. rental and maint.	1,234	1,078	1,145	1,170	1,172	1,027
Professional services	3,865	4,443	3,612	4,215	6,092	7,324
Travel	2,942	2,854	2,910	2,755	2,977	2,979
Equipment rentals	1,082	1,493	1,721	1,738	1,636	1,699
Miscellaneous	4,246	4,359	8,065	3,829	4,736	5,144
Loss on disposal	902	2,580	1,267	687	925	5,396
Write down of assets	-	-	506	-	-	-
Total	114,708	119,223	124,865	125,775	134,255	142,676
Percentage change		3.94%	4.73%	0.73%	6.74%	6.27%
Allocations						
Other - IOCC	(2,679)	(2,672)	(1,875)	(2,648)	(2,292)	(2,215)
Hydro capitalized	(12,044)	(15,461)	(17,164)	(20,716)	(21,276)	(20,723)
Cost recoveries	(1,390)	(1,815)	(4,190)	(4,748)	(5,198)	(7,874)
Sub-total	(16,113)	(19,948)	(23,229)	(28,112)	(28,766)	(30,812)
Net total	98,595	99,275	101,636	97,663	105,489	111,864
Percentage change		0.69%	2.38%	-3.91%	8.01%	6.04%

Note: "Loss on disposal", which is included above, is not included in Finance Schedule I, page 9 of 11.

Table 37: Other costs by category (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Other costs							
Salaries and fringe benefits	96,431	103,400	106,067	111,542	6,969	2,667	8,142
System equip. maint.	22,005	22,979	28,620	26,825	974	5,641	3,846
Insurance	2,422	2,689	2,579	2,607	267	(110)	(82)
Transportation	3,578	3,832	3,785	3,545	254	(47)	(287)
Office Supplies	2,595	2,629	2,392	2,804	34	(237)	175
Bldg. rental and maint.	1,186	1,149	1,228	1,217	(37)	79	68
Professional services	5,874	12,207	12,629	9,494	6,333	422	(2,713)
Travel	3,338	3,710	3,208	3,717	372	(502)	7
Equipment rentals	1,877	1,877	2,017	3,066	-	140	1,189
Miscellaneous	5,218	6,471	6,681	5,772	1,253	210	(699)
Loss on disposal	3,634	2,068	1,708	4,074	(1,566)	(360)	2,006
Write down of assets	-	-	-	-	-	-	-
Total	148,158	163,011	170,914	174,663	14,853	7,903	11,652
Percentage change	3.84%	10.03%	4.85%	7.15%			
Allocations							
Other - IOCC	(1,945)	(1,926)	(1,926)	(1,387)	19	-	539
Hydro capitalized	(21,656)	(23,326)	(24,090)	(23,954)	(1,670)	(764)	(628)
Cost recoveries	(9,111)	(9,623)	(10,900)	(7,069)	(512)	(1,277)	2,554
Sub-total	(32,712)	(34,875)	(36,916)	(32,410)	(2,163)	(2,041)	2,465
Net total	115,446	128,136	133,998	142,253	12,690	5,862	14,117
Percentage change	3.20%	10.99%	4.57%	11.02%			

In the table above we see that total other costs before allocations are forecast to increase by $14.9 million in 2014 test year over the 2013 actuals and total other costs before allocations are forecast to increase by $11.7 million in 2015 test year over the 2014 test year. On a net basis the costs for 2014 test year are forecast to exceed 2013 actuals by approximately $12.7 million and the costs for 2015 test year are forecast to exceed the 2014 test year by approximately $14.1 million.

We see that 2014 actual total other costs before allocations exceeded the 2014 forecast by $7.9 million. On a net basis, 2014 actuals exceed the 2014 forecast by $5.9 million.

In the table below we provide an analysis of total other costs on a kWh's sold and used basis for 2013 actuals, 2014 actuals and the 2014 and 2015 forecasts. This table shows that forecast total other costs have increased, and on a kWh basis, costs are forecast to increase as well. Actual cost per kWh for 2014 came in higher than both 2013 and the 2014 forecast and actual total other costs for 2014 were 4.6% higher than forecasted. The forecasted cost per kWh for 2015 is higher than the 2014 forecast and forecasted total other costs for 2015 are 11.0% higher than forecasted for 2014.

Table 38: Other costs per kWh

	2013			2014 Forecast		
kWh sold and used	6,974,000			7,503,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Salaries and fringe benefits	96,431	0.0138	83.53%	103,400	0.0138	80.70%
System equip. maint.	22,005	0.0032	19.06%	22,979	0.0031	17.93%
Insurance	2,422	0.0003	2.10%	2,689	0.0004	2.10%
Transportation	3,578	0.0005	3.10%	3,832	0.0005	2.99%
Office Supplies	2,595	0.0004	2.25%	2,629	0.0004	2.05%
Bldg. rental and maint.	1,186	0.0002	1.03%	1,149	0.0002	0.90%
Professional services	5,874	0.0008	5.09%	12,207	0.0016	9.53%
Travel	3,338	0.0005	2.89%	3,710	0.0005	2.90%
Equipment rentals	1,877	0.0003	1.63%	1,877	0.0003	1.46%
Miscellaneous	5,218	0.0007	4.52%	6,471	0.0009	5.05%
Loss on disposal	3,634	0.0005	3.15%	2,068	0.0003	1.61%
	148,158	0.0212	128.34%	163,011	0.0217	127.22%
Other - IOCC	(1,945)	(0.0003)	-1.68%	(1,926)	(0.0003)	-1.50%
Hydro capitalized	(21,656)	(0.0031)	-18.76%	(23,326)	(0.0031)	-18.20%
Cost recoveries	(9,111)	(0.0013)	-7.89%	(9,623)	(0.0013)	-7.51%
Total other costs (net)	115,446	0.0166	100.00%	128,136	0.0171	100.00%

	2014 Actual			2015 Forecast		
kWh sold and used	7,333,000			7,709,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Salaries and fringe benefits	106,067	0.0145	79.16%	111,542	0.0145	78.41%
System equip. maint.	28,620	0.0039	21.36%	26,825	0.0035	18.86%
Insurance	2,579	0.0004	1.92%	2,607	0.0003	1.83%
Transportation	3,785	0.0005	2.82%	3,545	0.0005	2.49%
Office Supplies	2,392	0.0003	1.79%	2,804	0.0004	1.97%
Bldg. rental and maint.	1,228	0.0002	0.92%	1,217	0.0002	0.86%
Professional services	12,629	0.0017	9.42%	9,494	0.0012	6.67%
Travel	3,208	0.0004	2.39%	3,717	0.0005	2.61%
Equipment rentals	2,017	0.0003	1.51%	3,066	0.0004	2.16%
Miscellaneous	6,681	0.0009	4.99%	5,772	0.0007	4.06%
Loss on disposal	1,708	0.0002	1.27%	4,074	0.0005	2.86%
	170,914	0.0233	127.55%	174,663	0.0227	122.78%
Other - IOCC	(1,926)	(0.0003)	-1.44%	(1,387)	(0.0002)	-0.98%
Hydro capitalized	(24,090)	(0.0033)	-17.98%	(23,954)	(0.0031)	-16.84%
Cost recoveries	(10,900)	(0.0015)	-8.13%	(7,069)	(0.0009)	-4.97%
Total other costs (net)	133,998	0.0183	100.00%	142,253	0.0185	100.00%

As part of our review, we have analysed each of these costs.

Salaries and fringe benefits

Gross payroll costs forecast for 2014 of $103.4 million are higher than 2013 levels by $7.0 million or 7.2%. Gross payroll costs forecast for 2015 of $111.5 million are higher than 2014 forecast levels by $8.1 million or 7.9%. These variations are outlined in the table below which summarizes salaries and fringe benefits costs incurred from 2007 to 2014 and the 2014 and 2015 forecast.

Table 39: Salaries and benefits by category (2007 - 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Salaries	$ 48,335	$ 47,280	$ 44,374	$ 45,402	$ 48,706	$ 51,818
Temporary salaries	-	-	5,900	6,700	7,034	6,272
Vacancy adjustment	-	-	-	-	-	-
	48,335	47,280	50,274	52,102	55,740	58,090
Other salary costs	-	1,269	2,009	3,009	668	562
Intercompany salaries	-	1,296	1,127	1,673	2,311	2,157
	48,335	49,845	53,410	56,784	58,719	60,809
Allowances	1,193	1,260	1,309	1,469	1,773	1,836
Directors fees	7	27	54	55	(3)	41
Overtime	6,109	7,580	7,778	8,675	9,460	10,633
Employee future benefits	5,861	5,559	4,334	6,098	7,247	6,970
Fringe benefits	7,065	7,007	7,029	7,254	7,672	8,064
Group insurance	1,460	1,719	2,336	2,052	2,546	2,403
Labrador travel benefit	141	126	131	130	142	151
Gross payroll costs	70,171	73,123	76,381	82,517	87,556	90,907
Less: capitalized salaries	(11,258)	(14,600)	(15,959)	(19,456)	(19,735)	(19,051)
Salaries and fringe benefits, net	$ 58,913	$ 58,523	$ 60,422	$ 63,061	$ 67,821	$ 71,856

Table 40: Salaries and benefits by category (2013 - 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Salaries	$ 54,299	$ 58,363	$ 56,851	$ 67,947	$ 4,064	$ (1,512)	$ 9,584
Temporary salaries	6,706	8,425	7,109	8,993	1,719	(1,316)	568
Vacancy adjustment	-	-	-	(3,336)	-	-	(3,336)
	61,005	66,788	63,960	73,604	5,783	(2,828)	6,816
Other salary costs	839	1,407	1,878	516	568	471	(891)
Intercompany salaries	2,633	2,832	3,188	1,783	199	356	(1,049)
	64,477	71,027	69,026	75,903	6,550	(2,001)	4,876
Allowances	1,907	1,853	1,997	1,801	(54)	144	(52)
Directors fees	38	117	43	85	79	(74)	(32)
Overtime	12,282	12,207	16,624	10,128	(75)	4,417	(2,079)
Employee future benefits	6,790	6,790	6,922	8,375	-	132	1,585
Fringe benefits	8,409	8,783	9,042	12,525	374	259	3,742
Group insurance	2,372	2,469	2,260	2,567	97	(209)	98
Labrador travel benefit	156	154	153	158	(2)	(1)	4
Gross payroll costs	96,431	103,400	106,067	111,542	6,969	2,667	8,142
Less: capitalized salaries	(20,185)	(21,944)	(22,613)	(22,654)	(1,759)	(669)	(710)
Salaries and fringe benefits, net	$ 76,246	$ 81,456	$ 83,454	$ 88,888	$ 5,210	$ 1,998	$ 7,432

Salaries

The salaries component of salaries and fringe benefits has maintained its upward trend from 2009 to 2015 test year. According to revision 1 of CA-NLH-104, the actual 2013 home based full time equivalent employees (FTEs) was 813. Home based FTEs increased to 865 in 2014 and increased to 903 in the 2015 test year.

The breakdown of salaries by division is summarized below:

Table 41: Salaries by division (2007 - 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Executive Leadership & Assoc.	$ 2,839	$ 348	$ 368	$ 334	$ 345	$ 367
Human Resources & Org. Effect.	3,264	3,221	3,295	3,349	3,891	4,136
Finance/CFO	7,178	6,332	6,652	6,281	6,039	6,123
Project Execution & Tech Services	5,901	6,162	7,246	8,209	7,034	6,565
Regulated Operations	30,470	32,189	34,293	33,660	38,060	40,076
Corporate Relations	-	-	-	2,150	2,425	2,519
Recharged Salaries	(1,317)	(972)	(1,580)	(1,881)	(2,054)	(1,696)
	$ 48,335	$ 47,280	$ 50,274	$ 52,102	$ 55,740	$ 58,090

Table 42: Salaries by division (2013 - 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance ($) '14F-'13	Variance ($) '14A-'14F	Variance ($) '15F-'14F
Executive Leadership & Assoc.	$ 506	$ 654	$ 681	$ 690	$ 148	$ 27	$ 36
Human Resources & Org. Effect.	4,486	5,484	4,489	5,312	998	(995)	(172)
Finance/CFO	6,168	7,541	7,492	8,319	1,373	(49)	778
Project Execution & Tech Services	6,144	7,452	7,010	8,239	1,308	(442)	787
Regulated Operations	40,295	42,096	41,262	46,033	1,801	(834)	3,937
Corporate Relations	2,498	2,648	2,539	3,099	150	(109)	451
System Operations	2,865	2,753	2,687	3,918	(112)	(66)	1,165
Recharged Salaries	(1,957)	(1,840)	(2,200)	(2,006)	117	(360)	(166)
	$ 61,005	$ 66,788	$ 63,960	$ 73,604	$ 5,783	$ (2,828)	$ 6,816

Salary fluctuations were noted within several of the divisions when comparing the 2014 forecast to 2013 actuals, the 2014 forecast to 2014 actuals and the 2015 forecast to the 2014 forecast, however the most significant increases occurred within the following divisions - Human Resources & Organizational Effectiveness, Finance/CFO, Project Execution & Tech Services, Regulated Operations and System Operations.

According to Hydro, the forecast increase in the Human Resources & Organizational Effectiveness division for the 2014 test year compared to the 2013 year is primarily due to an increase in apprentice positions. This increase makes up $0.7 million of the $1.0 million and the remainder included economic, merit, and progression salary adjustments. The decrease in the Human Resources & Organizational Effectiveness division for the 2014 year compared to the 2014 test year is primarily due to higher than anticipated vacancies, mainly attributed to apprentice positions not filled.

According to Hydro, the increase in the Finance/CFO division for the 2014 test year compared to the 2013 year is primarily due to an FTE increase, which accounts for $1.1 million of the $1.4 million variance. The remainder included economic, merit and progression salary adjustments.

According to Hydro, the increase in the Project Execution and Technical Services division for the 2014 test year compared to the 2013 year is due to the FTEs transferred from this division to the reorganization of System Planning and Operations.

According to Hydro, the increase in the Regulated Operations division for the 2014 test year compared to the 2013 year is due to the FTEs transferred from this division to the reorganization of System Planning and Operations. The decrease in the Regulated Operations division for the 2014 year compared to the 2014 test year are due to higher than anticipated vacancies. The increase in the Regulated Operations division for the 2015 test year compared to the 2014 test year is primarily due to the increase in salaries associated with a FTE increase. This accounts for $1.8 million of the variance with the remaining amount including economic, merit, progression and front line supervisor adjustment. In addition, according to Hydro the 3% economic adjustment for union employees was included in the 2015 forecast, but not in the 2014 forecast.

According to Hydro, the increase in the Systems Operations division for the 2015 test year compared to the 2014 test year is due to the addition of two new teams, Ready for Integration and Building the Production

Organization, as well as several vacancies forecast to be filled in 2015. This accounts for $1.1 million of the variance with the remaining amount including economic, merit, and progression salary adjustments.

Consistent with 2013, the Company has implemented a salary compensation matrix for non-union employees. This matrix illustrates a scale for salary increases and bonuses based on performance ranging from 0-10% (inclusive general adjustment of 4% for 2013; 3% for 2014; and 2% for 2015). The compensation matrix allows for pay adjustments above the scale maximum based on an employee's "rating of performance". Ratings of performance include Unacceptable, Improvement Required, Meets Expectations, Exceeds Expectations, and Exceptional.

As noted by the Company, all salary adjustment figures include a general scale adjustment of 4% for 2013, 3% for 2014 and 2% for 2015 and all are calculated as a percentage of current base salary. All salary adjustments are subject to a scale maximum. Those in Exceeds Expectations and Exceptional categories whose performance adjustment would exceed the scale maximum receive the balance in the form of a one-time cash bonus of 3% or 6%, respectively, of their base salary.

There have been no changes in the compensation matrix from 2013 to 2015, except in relation to the general scale adjustments noted above.

Table 43: Compensation matrix

	Scale Adjustment - Below Scale Maximum		
Rating of Performance	**2015**	**2014**	**2013**
Exceptional	10% (with cash payout of balance)	10% (with cash payout of balance)	10% (with cash payout of balance)
Exceed Expectations	8.5 % (with cash payout of balance)	8.5 % (with cash payout of balance)	8.5 % (with cash payout of balance)
Meets Expectations	7% (to the scale maximum)	7% (to the scale maximum)	7% (to the scale maximum)

Full Time Equivalents

An analysis of net full time equivalent employees (FTEs) by year and by division or department has proven to be useful in the past in assessing changes in salary costs or forecast of costs for future years. Net FTEs are operating FTEs plus or minus operating and capital labour recharges from and to other Nalcor lines of business. The table below is a detailed comparison of the number of net FTEs by division for 2007 to 2015 forecast. The table was compiled from net FTEs provided by Hydro.

Table 44: Net FTEs by division (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Executive Leadership & Assoc.	13	7	6	5	4	4
Human Resources & Org. Effect.	59	54	53	58	63	62
Finance/CFO	101	93	91	88	87	83
Project Execution & Tech Services	77	78	87	94	78	75
Regulated Operations	524	525	527	524	532	537
Corporate Relations	39	40	40	40	41	40
Systems Operations and Planning	-	-	-	-	-	-
	813	797	804	809	805	801

Table 45: Net FTEs by division (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Executive Leadership & Assoc.	5	7	8	7	2	1	-
Human Resources & Org. Effect.	65	31	27	29	(34)	(4)	(2)
Finance/CFO	81	89	89	94	8	-	5
Project Execution & Tech Services	79	93	87	89	14	(6)	(4)
Regulated Operations	538	575	553	594	37	(22)	19
Corporate Relations	39	39	39	43	-	-	4
Systems Operations and Planning	-	26	25	34	26	(1)	8
	807	860	828	890	53	(32)	30

As shown, in comparison to 2013 the FTEs for 2014 is expected to decrease by 34 full time positions in the Human Resources and Org. Effect. Division. According to Hydro, this is due to the transfer of apprentice from HROE to other departments.

According to Hydro, the increase in FTEs in the Regulated Operations division in the 2014 test year compared to the 2013 year is due to transfers of FTEs from the Human Resources and Org. Effect. Division and additional apprentices being anticipated for the 2014 year, partially offset by transfers to the System Operations and Planning Division. The decrease in FTEs in the 2014 year compared to the 2014 test year is due to higher than anticipated vacancies. The increase in FTEs in the 2015 test year compared to the 2014 test year is due to new positions and vacancies in Hydro Generation, Thermal Generation and Transmission and Rural Operations.

According to Hydro, the increase in FTEs in the Systems Operations and Planning Division in the 2014 test year over 2013 is due to the reorganization of this division by transferring FTEs from the Project Execution and Technical services division and the Regulated Operations division.

A comparison of average salary per net FTE for 2007 to 2014 and the 2014 and 2015 forecast are included in the following table:

Table 46: Average salary per Net FTE (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Salary costs (including temporary salaries) (Note 1)	$ 48,335	$ 47,280	$ 50,274	$ 52,102	$ 55,740	$ 58,090
Intercompany salaries	-	1,296	1,127	1,673	2,311	2,157
	$ 48,335	$ 48,576	$ 51,401	$ 53,775	$ 58,051	$ 60,247
FTEs	813	797	804	809	805	801
Average salary per net FTE	$ 59,453	$ 60,949	$ 63,932	$ 66,471	$ 72,113	$ 75,215
% increase		2.52%	4.89%	3.97%	8.49%	4.30%

Note 1: Salary costs do not include capital charges in/out.

Table 47: Average salary per Net FTE (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Salary costs & Vacancy Adjustment (including temporary salaries) (Note 1)	$ 61,005	$ 66,788	$ 63,960	$ 73,604	$ 5,783	$ (2,828)	$ 6,816
Intercompany salaries	2,633	2,832	3,188	1,783	199	356	(1,049)
	$ 63,638	$ 69,620	$ 67,148	$ 75,387	$ 5,982	$ (2,472)	$ 5,767
FTEs	807	860	828	890	53	(32)	30
Average salary per net FTE	$ 78,857	$ 80,953	$ 81,097	$ 84,704			
% increase	4.84%	2.66%	2.84%	4.63%			

Note 1: Salary costs do not include capital charges in/out.

The above analysis indicates that the average salary per net FTE is expected to increase by 4.63% in 2015. Hydro's provided the following table to explain the expected increase based on Home Based FTEs:

Table 48: Hydro's Explanation of Average Salary Increase in 2015 Test Year

Description 000's	2014 Test Year	2015 Test Year	Variance
Salaries (Home Based)	$ 68,627	$ 78,945	$ 10,318
Retro accrued (Note 1)	945	-	(945)
Vacancy Allowance	-	3,336	3,336
Salaries Less Vac. Allow.	$ 69,572	$ 75,609	$ 6,038
Home Based FTEs	865	903	38
Average Salary	$ 80.4	$ 83.7	$ 3.3
% Increase		4.1%	

Note 1: The 2014 Test Year amount noted above was restated to reflect the the 3% wage adjustment for unionized employees for April 1, 2014, processed in May 2015, that was accrued in another salary account.

According to Hydro, the average salary increase per home based FTE forecast for 2015 compared to 2014 test year includes economic, progression, merit, and front line supervisor adjustments. The 2015 forecast was also increased by 3% for the 2014 adjustment for union employees.

Executive Salaries

The table below outlines the portion of executive salaries, including the total hours and average billing rates, which were charged back to Hydro by Nalcor for 2011 to 2014, and test year 2014 and 2015:

Table 49: Executive salaries by position

	2015 Test Year			2014 Test Year		
	Hours	Average Billing Rates	Recharge Amount	Hours	Average Billing Rates	Recharge Amount
President and CEO	155.0	$ 458.46	$ 71,061	408.0	$ 444.63	$ 181,411
VP, HROE	393.0	187.92	73,852	1,121.0	175.47	196,697
VP, Project Execution and Technical Services	452.0	226.28	102,280	501.0	221.93	111,189
VP, Finance and CFO	48.0	230.00	11,040	38.0	223.55	8,495
VP, Corporate Relations	266.0	161.27	42,899	979.0	157.29	153,989
VP, Strategic Planning & Business Development				153.0	183.40	28,060
	1,314.0	$ 229.17	$ 301,132	3,200.0	$ 212.45	$ 679,841
% change	-59%	8%	-56%	135%	8%	154%

	2014 Actual			2013 Actual		
	Hours	Average Billing Rates	Recharge Amount	Hours	Average Billing Rates	Recharge Amount
President and CEO	561.0	$ 445.45	$ 249,899	137.0	$ 427.29	$ 58,539
VP, HROE	1,595.0	170.66	272,196	302.0	178.10	53,786
VP, Project Execution and Technical Services	522.0	222.27	116,023	365.5	214.50	78,400
VP, Finance and CFO	258.0	222.90	57,507	60.5	217.04	13,131
VP, Corporate Relations	978.0	157.71	154,240	496.5	127.70	63,403
VP, Strategic Planning & Business Development	176.0	183.27	32,255			
	4,090.0	$ 215.68	$ 882,120	1,361.5	$ 196.30	$ 267,259
% change from 2014 test year	28%	2%	30%			
% change from 2013	200%	10%	230%			
% change from 2012				4%	-5%	-2%

	2012 Actual			2011 Actual		
	Hours	Average Billing Rates	Recharge Amount	Hours	Average Billing Rates	Recharge Amount
President and CEO	154.5	$ 417.20	$ 64,457	133.5	$ 402.45	$ 53,727
VP, HROE	392.5	169.14	66,389	996.0	161.36	160,719
VP, Project Execution and Technical Services	451.5	205.55	92,805	697.0	195.36	136,168
VP, Finance and CFO	48.0	208.69	10,017	88.5	198.41	17,559
VP, Corporate Relations	265.5	141.92	37,680			
	1,312.0	$ 206.82	$ 271,348	1,915.0	$ 192.26	$ 368,173
% change	-31%	8%	-26%	-33%	21%	-19%

In 2014, the total recharge amount from executives is forecast to increase by $412,582 (154%) compared to 2013 due to an increase of 1,838 hours (135%), and an 8% increase in the weighted average billing rate. In 2015, the total recharge amount from executive is forecast to decrease by $378,709 (56%) compared to the 2014 forecast due to a decrease of 1,886 hours (59%), partially offset by a 8% increase in the weighted average billing rate.

The following table outlines the change in executive hours from Nalcor to Hydro and average billing rates from 2013 to test year 2015:

Table 50-1: Comparison of hours and average billing rates

Hours	2013	2014F	2014	2015F	Variance Hours 2014F-2013	Variance % 2014F-2013	Variance Hours 2015F-2014F	Variance % 2015F-2014F
President and CEO	137.0	408.0	561.0	155.0	271.0	197.8%	(253.0)	-62.0%
VP, HROE	302.0	1,121.0	1,595.0	393.0	819.0	271.2%	(728.0)	-64.9%
VP, Project Execution and Technical Services	365.5	501.0	522.0	452.0	135.5	37.1%	(49.0)	-9.8%
VP, Finance and CFO	60.5	38.0	258.0	48.0	(22.5)	-37.2%	10.0	26.3%
VP, Corporate Relations	496.5	979.0	978.0	266.0	482.5	97.2%	(713.0)	-72.8%
VP, Strategic Planning & Business Development	-	153.0	176.0	-	153.0	100.0%	(153.0)	-100.0%
	1,361.5	3,200.0	4,090.0	1,314.0	1,838.5	135.0%	(1,886.0)	-58.9%

Average billing rate	2013	2014F	2014	2015F	Variance $ 2014F-2013	Variance % 2014F-2013	Variance $ 2015F-2014F	Variance % 2015F-2014F
President and CEO	$ 427.29	$ 444.63	$ 445.45	$ 458.46	$ 17.34	4.1%	$ 13.82	3.1%
VP, HROE	178.10	175.47	170.66	187.92	(2.63)	-1.5%	12.45	7.1%
VP, Project Execution and Technical Services	214.50	221.93	222.27	226.28	7.43	3.5%	4.35	2.0%
VP, Finance and CFO	217.04	223.55	222.90	230.00	6.51	3.0%	6.45	2.9%
VP, Corporate Relations	127.70	157.29	157.71	161.27	29.59	23.2%	3.98	2.5%
VP, Strategic Planning & Business Development	-	183.40	183.27	-	183.40	100.0%	(183.40)	-100.0%
Weighted average	$ 196.30	$ 212.45	$ 215.68	$ 229.17	$ 16.15	8.2%	$ 16.72	7.9%

As noted in the above table, the total time forecast to be charged by Nalcor Executives in 2014 test year increased by 1,838 hours compared to the 2013 year. The most significant items impacting the total time charged is the President and CEO, the VP of HROE., and the Vice President of Corporate Relations. According to Hydro, this increase in hours is mainly due to the follow up activity related to the January 2014 supply interruption. Additionally, VP of HROE was seconded to lead the coordination of the Outage and Electricity System reviews for Hydro.

In PUB-NLH-228, Hydro reforecast 2014 and 2015 for the portion of executive salaries, including the total hours and average billing rates, which are forecast to be charged back to Hydro by Nalcor. The following table presents the reforecast:

Table 50-2: Executive salaries by position – Reforecast 2014 and 2015

	2015 Forecast			2014 Forecast		
	Hours	Average Billing Rates	Recharge Amount	Hours	Average Billing Rates	Recharge Amount
President and CEO	561.0	$ 459.53	$ 257,798	561.0	$ 445.04	$ 249,669
VP, HROE	1,121.0	188.16	210,926	1,462.0	178.08	260,356
VP, Project Execution and Technical Services	452.0	226.28	102,280	522.0	221.75	115,754
VP, Finance and CFO	350.0	230.00	80,500	300.0	223.58	67,075
VP, Corporate Relations	979.0	161.58	158,184	979.0	157.29	153,989
VP, Strategic Planning & Business Development				153.0	183.40	28,060
	3,463.0	$ 233.81	$ 809,688	3,977.0	$ 219.99	$ 874,903

The change from Test Year 2014 to reforecast 2014 is an increase of 777 hours and $195,062, and the change from Test Year 2015 to reforecast 2015 is an increase of 2,149 hours and $508,556. According to Hydro, the hours and associated dollars restated reflect the level of activity in 2014 based on actual to the end of November 2014.

Capitalized Salaries

Capitalized salaries include the salaries and benefits of the Company's employees whose time is charged directly to capital projects, as well as departmental and non-departmental overhead. The gross payroll costs incurred from 2007 to 2014 and forecast for 2014 and 2015 have been allocated to operations and capital as follows:

Table 51: Payroll charged to operating and capital (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Payroll charged to operating	58,913	58,523	60,422	63,061	67,821	71,856
Payroll charged to capital	11,258	14,600	15,959	19,456	19,735	19,051
	70,171	73,123	76,381	82,517	87,556	90,907

Table 52: Payroll charged to operating and capital (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Payroll charged to operating	76,246	81,456	83,454	88,888	5,210	1,998	7,432
Payroll charged to capital	20,185	21,944	22,613	22,654	1,759	669	710
	96,431	103,400	106,067	111,542	6,969	2,667	8,142

As shown, the capitalized payroll is forecast to increase in 2014 by $1.8 million over 2013. According to Hydro, this is due to an increase in Hydro's capital program and salary and benefit increases.

Capitalized salaries forecast for 2015 are 3.2% higher than 2014 test year.

Other Salary Costs

Other salary costs are forecast to decrease by $891,000 in 2015 over the 2014 test year. According to Hydro, this is primarily due to retro pay for the expiration of the collective agreement in 2014.

Intercompany salaries

Intercompany salaries are forecast to decrease by $1.0 million in 2015 over the 2014 test year. According to Hydro, this primarily relates to the Finance and Corporate Communications divisions. Staff from these divisions were transferred from Nalcor to Hydro resulting in a reduction in labour charged in to Hydro. There was also a reduction in the Executive group as the 2014 forecast includes incremental activity in the first part of 2014 related to outage activities.

Overtime

Annual overtime costs vary based on circumstances such as emergencies, which may arise due to weather and equipment related outages, labour shortages and capital project requirements. Overtime costs in 2015 are forecast to decrease by $2.1 million over the 2014 test year. According to Hydro, this is primarily due to additional forecast FTEs.

In order to gain a better understanding of forecast overtime, we have prepared a comparison of actual and budgeted gross overtime. This analysis is provided in the table below:

Table 53: Comparison of overtime – actual to budget

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Actuals 2013	Actuals 2014
Overtime	6,109	7,580	7,778	8,675	9,460	10,633	12,282	16,624
Overtime budget	2,774	3,804	4,013	4,709	5,461	5,582	8,604	12,207
Over (under) budget ($)	3,335	3,776	3,765	3,966	3,999	5,051	3,678	4,417
Over (under) budget (%)	120.22%	99.26%	93.82%	84.22%	73.23%	90.49%	42.75%	36.18%

Note 1: The 2014 "budget" figure is the Company's 2014 Test Year Forecast.

Based on the information provided above, Hydro's actual gross overtime costs exceed budgeted costs each year.

The actual overtime costs for 2014 increased by $4.4 million over the 2014 test year. According to Hydro, $3.7 million of this increase was due to Regulated Operations related to winter readiness and maintenance related activities.

Employee future benefits

Employee future benefit costs relate to severance payments upon retirement and health benefits provided to retirees on a cost shared basis. These costs include assumptions as to future benefit costs and interest rate expectations. According to Hydro, no actuarial report is available for the 2014 and 2015 test year. Forecasts are based off the 2013 actuarial report. Employee future benefits are forecast to increase by $1.6 million from the 2014 test year to 2015 test year. This increase is primarily due to the proposed amortization of actuarial losses.

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 following tables present fringe benefits as a percentage of salaries for 2007 to 2014 actuals and 2014 and 2015 forecasts.

Table 54: Fringe benefits as a percentage of salaries (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Salaries	$ 48,335	$ 47,280	$ 50,274	$ 52,102	$ 55,740	$ 58,090
Fringe benefits	$ 7,065	$ 7,007	$ 7,029	$ 7,254	$ 7,672	$ 8,064
	14.62%	14.82%	13.98%	13.92%	13.76%	13.88%

Table 55: Fringe benefits as a percentage of salaries (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Salaries	$ 61,005	$ 66,788	$ 63,960	$ 73,604	$ 5,783	$ (2,828)	$ 6,816
Fringe benefits	$ 8,409	$ 8,783	$ 9,042	$ 12,525	$ 374	$ 259	$ 3,742
	13.78%	13.15%	14.14%	17.02%	-0.63%	0.99%	3.87%

Fringe benefits as a percentage of salaries increased by 3.87% in 2015 test year compared to 2014 test year. According to Hydro, this was mainly due to increase of the employee and matching employer contributions to the Public Service Pension Plan (PSPP) as per the announcement of the PSPP reform. The matching employer contribution increased 2.15% of all pensionable earnings for all plan members and an additional 1.1% for the portion of pensionable earnings above the year's CPP maximum pensionable earnings.

Vacancy credit

Included in the salary forecast for 2015 is a vacancy credit of $3.3 million. When compared to the $980,000 vacancy credit included in the 2007 test year, the difference is quite significant. Per CA-NLH-104, Hydro's method of forecasting vacancies combines a review of past vacancy experience and current year vacancy experience, with a particular emphasis on the prior and current year trends. A vacancy analysis is done at least twice per year, taking into account the anticipated retirements, leave of absences, voluntary resignations, and new hires. Additionally, there is consultation with the area management teams to review the status of job competitions and assist in confirming expected file dates for positions in their respective area.

According to Hydro, the $3.3 million represents the 2015 budgeted allowance for 40 vacancies and the vacancy impact in the 2014 test year is absorbed within the forecast data.

System equipment maintenance

System equipment maintenance costs have been forecast to increase by approximately $974,000 in 2014 in comparison to 2013 and are forecast to increase by $3.8 million in 2015 in comparison to the 2014 test year. Actual system equipment maintenance costs in 2014 increased by $5.6 million compared to the 2014 test year. The following table summarizes system equipment maintenance costs incurred from 2007 to 2014 and 2014 and 2015 forecasts.

Table 56: System equipment maintenance costs by category (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Maintenance material	22,117	20,815	17,899	17,780	10,961	9,784
Contract labour	-	-	-	-	7,312	8,378
Contract materials	-	-	-	-	57	21
Extraordinary repair amortization	-	-	2,715	2,582	1,644	605
	22,117	20,815	20,614	20,362	19,974	18,788
Tools and operating supplies	348	383	369	398	349	415
Freight expense	393	389	411	399	471	383
Lubricant, gases & chemicals	667	695	728	589	718	675
	23,525	22,282	22,122	21,748	21,512	20,261

Table 57: System equipment maintenance costs by category (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Maintenance material	11,278	11,131	13,263	11,615	(147)	2,132	484
Contract labour	8,676	9,919	13,067	14,453	1,243	3,148	4,534
Contract materials	120	167	140	98	47	(27)	(69)
Extraordinary repair amortization	-	-	-	(996)	-	-	(996)
	20,074	21,217	26,470	25,170	1,143	5,253	3,953
Tools and operating supplies	499	452	507	473	(47)	55	21
Freight expense	536	440	681	460	(96)	241	20
Lubricant, gases & chemicals	896	870	962	722	(26)	92	(148)
	22,005	22,979	28,620	26,825	974	5,641	3,846

The total of maintenance material, extraordinary repair amortization, contract labour and contract materials cost are forecast to increase by $1.1 million in 2014 over 2013 actuals and are forecast to increase by $4.0 million in 2015 over 2014 forecasts. Maintenance costs are incurred throughout all divisions with the majority of costs incurred in the Regulated Operations division. The following table provides a breakdown of Maintenance costs by division from 2007 to 2014 and 2014 and 2015 forecast.

Table 58: System equipment maintenance costs by division (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Executive Leadership & Assoc.	98	63	71	3	-	-
Human Resources & Org. Effect.	19	75	135	190	46	26
Finance/CFO	1,184	1,071	1,173	1,317	1,212	1,306
Project Execution & Tech Services	142	147	131	189	161	133
Regulated Operations	20,674	19,459	19,104	18,483	18,377	17,185
Corporate Relations	-	-	-	180	178	138
	22,117	20,815	20,614	20,362	19,974	18,788

Table 59: System equipment maintenance costs by division (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Executive Leadership & Assoc.	-	7	-	8	7	(7)	1
Human Resources & Org. Effect.	29	68	79	75	39	11	7
Finance/CFO	1,364	1,348	1,604	1,199	(16)	256	(149)
Project Execution & Tech Services	774	236	162	244	(538)	(74)	8
Regulated Operations	17,792	19,427	24,418	23,503	1,635	4,991	4,076
Corporate Relations	115	126	204	131	11	78	5
System Operations	-	5	3	10	5	(2)	5
	20,074	21,217	26,470	25,170	1,143	5,253	3,953

The majority of the costs expended in all years occur within the Regulated Operations division. The following table provides a breakdown of maintenance material for the Regulated Operations division for the years 2007 to the 2015 forecast:

Table 60: Regulated Operations division costs by department (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
System Operation	170	186	215	2	3	3
Hydro Generation	1,583	1,328	1,190	1,385	1,392	2,153
Thermal Holyrood	11,802	11,023	10,664	9,437	9,599	7,433
Central operations	4,725	4,634	4,684	5,291	5,231	5,539
Labrador operations	1,252	1,476	1,429	1,323	1,331	1,132
Northern operations	1,142	812	922	1,045	821	925
	20,674	19,459	19,104	18,483	18,377	17,185

Table 61: Regulated Operations division costs by department (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
System Operation	4	-	-	-	(4)	-	-
Hydro Generation	1,386	1,668	1,639	1,598	282	(29)	(70)
Thermal Holyrood	7,480	7,661	9,983	7,712	181	2,322	51
Central operations	1,851	2,459	4,950	3,704	608	2,491	1,245
Labrador operations	1,292	1,238	1,577	3,868	(54)	339	2,630
Northern operations	989	1,161	1,044	952	172	(117)	(209)
Other	4,790	5,240	5,225	5,669	450	(15)	429
	17,792	19,427	24,418	23,503	1,635	4,991	4,076

The most significant portion of the $1.6 million increase in the 2014 test year over the 2013 year is within the Central Operations department. According to Hydro, this $608,000 increase in the Central Operations department is due to the completion of preventative and corrective maintenance backlog work associated with critical power transformers, air blast circuit breakers and protection and control systems.

The most significant portion of the $5.0 million increase in the 2014 year over the 2014 test year is within the Thermal Holyrood department and the Central Operations department. According to Hydro, the $2.3 million increase in the Thermal Holyrood department is due to an increase in Holyrood Unit 1 annual maintenance costs, condition assessments, heater and boiler pump repairs and engineering related activities. According to Hydro, the $2.5 million increase in the Central Operations department is due to maintenance backlog reductions, transportation costs to relocate a transformer, Stephenville gas turbine repairs and other repair and engineering related activities.

The most significant portion of the $4.1 million increase in the 2015 test year over the 2014 test year is within the Central Operations department and the Labrador Operations department. According to Hydro, the $1.2 million increase in the Central Operations department is primarily due to the new combustion turbine ($2.6M), partially offset by reductions in corrective and preventative backlog activity ($0.7M) and the inclusions of the extraordinary maintenance cost deferral of $0.9 million in 2015. According to Hydro, the $2.6 million increase in the Labrador Operations department is primarily due to the inclusion of $2.8 million in costs related to the maintenance of transmission assets in Labrador, formerly used by TwinCo to service iron ore mines and rural customers in Labrador West.

A significant portion of the cost expended in this division is within the Thermal Holyrood department. For further analysis, the breakdown of costs at the Holyrood thermal plant is as follows:

Table 62: Thermal Holyrood department costs by unit (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Unit # 1	2,085	1,598	3,583	1,555	832	1,517
Unit # 2	1,484	2,158	1,170	477	2,708	1,668
Unit # 3	3,105	1,739	521	2,374	1,943	1,024
Annual routine maintenance (Note 1)	5,128	5,528	5,390	5,031	4,116	3,224
	11,802	11,023	10,664	9,437	9,599	7,433

Note 1: Annual routine maintenance includes Extraordinary repair amortization.

Table 63: Thermal Holyrood department costs by unit (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Unit # 1	1,406	1,634	2,905	1,720	228	1,271	86
Unit # 2	836	1,692	2,189	1,720	856	497	28
Unit # 3	1,766	1,430	1,286	1,488	(336)	(144)	58
Annual routine maintenance (Note 1)	3,472	2,905	3,603	2,784	(567)	698	(121)
	7,480	7,661	9,983	7,712	181	2,322	51

Note 1: Annual routine maintenance includes Extraordinary repair amortization.

According to Hydro, forecasting for System Equipment Maintenance costs is prepared by preventive and corrective program requirements, consultation with contractors on the upcoming annual work packages as well as knowledge and history of the equipment and processes.

Costs relating to Unit #2 were forecast to increase in 2014 by $856,000 over 2013. According to Hydro, this is primarily due to boiler work in 2014. In 2013, the unavailability of Unit #1 prevented an outage window for work on Unit #2 and so the work was completed in 2014.

Actual costs for 2014 were $2.3 million higher than forecast. This is primarily due to an increase in cost related to Unit #1 and a decrease in annual routine maintenance. According to Hydro, the increase in costs related to Unit #1 is primarily due to additional work completed to address vibration issues and balancing required on Turbine Rotor. According to Hydro, the increase in annual routine maintenance is primarily due to additional work completed related to Marine Terminal electrical grounding, winter readiness, NL Power Mobile Unit, and miscellaneous maintenance and repairs.

Professional services

For 2014 and 2015, we compared the forecast amount to prior years, investigated any unusual fluctuations and assessed overall reasonableness of the forecast amounts. Professional services costs from 2007 to 2015 are as follows:

Table 64: Professional services costs by category (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Consultants	2,312	2,674	2,114	2,335	3,024	4,145
PUB Related Costs	620	801	939	882	1,934	1,835
Software Acquisitions & Maintenance	933	968	559	998	1,134	1,344
	3,865	4,443	3,612	4,215	6,092	7,324

Table 65: Professional services costs by category (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Consultants	3,384	7,281	7,260	5,721	3,897	(21)	(1,560)
PUB Related Costs	1,244	3,488	3,815	2,290	2,244	327	(1,198)
Software Acquisitions & Maintenance	1,246	1,438	1,554	1,483	192	116	45
	5,874	12,207	12,629	9,494	6,333	422	(2,713)

According to Hydro, the $2.2 million increase in PUB related costs in the 2014 test year over the 2013 year is due to an estimated $1.1 million increase in GRA costs and amortization and a $1.2 million increase in consultants/legal costs related to internal legal and consulting costs related to the GRA and with Board Ordered Intervener costs and internal legal and consulting costs related to other applications.

According to Hydro, the $1.2 million decrease in PUB related costs in the 2015 test year over the 2014 test year is due to a decrease of $0.6 million in consultants/legal costs related to a decrease in the volume of applications and regulatory activity. GRA costs and amortization in the 2015 test year include an amortization of $0.3 million compared to $1.0 million in the 2014 test year associated with Board ordered intervener costs.

Consultants' fees (including audit and legal), which represent the largest portion of total professional fees, were approximately $3.4 million in 2013 and are forecast to be approximately $7.3 million in 2014 and $5.7 million in 2015. The increase of $3.9 million in forecast 2014 over 2013 is primarily the result of higher costs in the Finance/CFO division and the Regulated Operations division, and the decrease of $1.6 million in forecast 2015 over forecast 2014 is primarily due to the result of lower costs in the Finance/CFO division, the Regulated Operations division and the Corporate Relations division. Details by division are indicated in the table below:

Table 66: Consultants' fees by division (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Executive Leadership & Assoc.	275	217	231	99	90	201
Human Resources & Org. Effect.	286	317	465	639	846	777
Finance/CFO	335	423	263	285	277	494
Project Execution & Tech Services	175	231	316	331	311	477
Regulated Operations	1,241	1,486	839	592	910	1,157
Corporate Relations	-	-	-	389	590	1,039
System Operations	-	-	-	-	-	-
	2,312	2,674	2,114	2,335	3,024	4,145

Table 67: Consultants' fees by division (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Executive Leadership & Assoc.	191	144	2,340	178	(47)	2,196	34
Human Resources & Org. Effect.	707	1,133	833	1,165	426	(300)	32
Finance/CFO	335	2,245	468	1,384	1,910	(1,777)	(861)
Project Execution & Tech Services	233	346	177	308	113	(169)	(38)
Regulated Operations	778	2,114	2,080	1,451	1,336	(34)	(663)
Corporate Relations	1,140	1,172	1,101	467	32	(71)	(705)
System Operations	-	127	261	768	127	134	641
	3,384	7,281	7,260	5,721	3,897	(21)	(1,560)

Consultants' fees were forecast to increase by $3.9 million in 2014 compared to 2013 actuals. The two largest variances occurred in the Finance/CFO division and the Regulated Operation division. According to Hydro, the $1.9 million increase in the Finance/CFO division in the 2014 test year over the 2013 year is primarily due to forecasted outage inquiry costs in 2014. The $1.3 million increase in the Regulated Operation division is primarily due to increased condition assessments and engineering related activities, environmental work, and environmental remediation at Sunnyside Terminal Station that all took place in 2014.

Actual 2014 consultants' fees in the Executive Leadership & Associates division increased by $2.2 million compared to the 2014 test year and decreased in the Finance/CFO division by $1.8 million. According to Hydro, this is primarily due to outage inquiry costs and because outage costs were forecasted in the Finance division, but actuals were recorded in the Executive division.

Consultants' fees are forecast to decrease by $1.6 million in 2015 compared to the 2014 test year. The three largest variances occurred in in the Finance/CFO, Regulated Operations, and Corporate Operations divisions. According to Hydro, the decrease of $0.9 million in the Finance/CFO division is primarily due to the inclusion of outage inquiry costs in the 2014 forecast. The $0.7 million decrease in the Regulated operations division was primarily due to decreased condition assessments and engineering related activities, environmental work, and environmental remediation at Sunnyside Terminal Station, partially offset by a miscellaneous increase in consulting costs. The $0.7 million decrease in the Corporate Relations division is primarily due to CDM related program costs that came from the Isolated Systems Community Program that was not forecast in 2015.

Hydro has estimated that there will be $3.5 million in 2014 for regulatory costs related to the Board and $2.3 million for 2015. A listing of the major projects included under PUB related costs for 2014 and 2015 forecast, along with a comparison to the Company's actual results for 2014, is set out below:

Table 68: PUB related costs

(000)'s

PUB Related Costs	Forecast 2014	Actual 2014	Forecast 2015	Variance '14A-'14F	Variance '15F-'14F
PUB Annual Assessment	$ 735	$ 691	$ 750	$ (44)	$ 15
Consultants/Legal	1,613	1,708	1,067	95	(546)
GRA Costs and Amortization	1,000	1,281	333	281	(667)
Capital Budget	80	80	80	-	-
Annual Financial Reviews	60	55	60	(5)	-
Total	$ 3,488	$ 3,815	$ 2,290	$ 327	$ (1,198)

The variance between 2015 test year and 2014 test year is primarily due to GRA costs and amortization. Hydro has proposed to defer and amortize $1.0 million in costs relating to the current GRA over a three year period commencing in 2015, discussed in further detail in the Deferred Accounts section of this report.

Miscellaneous

The breakdown of items included in the miscellaneous expense category from 2007 to 2014 and forecast 2014 and 2015 is as follows:

Table 69: Miscellaneous costs by category (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Business and payroll taxes	2,584	2,736	2,807	2,933	2,967	3,177
Bad debt expense	277	(37)	3,884	(631)	116	134
Staff training	820	800	730	668	647	780
Write offs	(43)	304	105	239	179	329
Employee expenses	353	302	332	347	427	354
Sundry costs	161	179	128	161	142	197
Diesel fuel Hydro	71	61	58	70	104	13
Energy management	15	6	13	36	148	154
Collection fees	8	8	8	6	6	6
	4,246	4,359	8,065	3,829	4,736	5,144

Table 70: Miscellaneous costs by category (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Business and payroll taxes	3,424	3,495	3,629	3,721	71	134	226
Bad debt expense	71	120	166	111	49	46	(9)
Staff training	842	854	716	839	12	(138)	(15)
Write offs	82	60	25	59	(22)	(35)	(1)
Employee expenses	398	420	525	398	22	105	(22)
Sundry costs	205	234	251	216	29	17	(18)
Diesel fuel Hydro	82	126	29	198	44	(97)	72
Energy management	109	1,156	1,334	224	1,047	178	(932)
Collection fees	5	6	6	6	1	-	-
	5,218	6,471	6,681	5,772	1,253	210	(699)

Miscellaneous expenses are forecast to increase in 2014 test year over 2013 actual by approximately $1.3 million or 24.0 % and are forecast to decrease in 2015 over 2014 test year by approximately $699,000 or 10.8%. These variances are primarily related to energy management.

Energy management expenses are forecast to increase by approximately $1.0 million in 2014 test year over 2013 actual and are forecast to decrease by approximately $932,000 in 2015 over 2014 test year. According to Hydro, this is due to CDM related program costs, primarily due to an uptake in the industrial program in 2014.

Loss on Disposal

In 2014, loss on disposal of assets is expected to total approximately $2.1 million and in 2015, is expected to total approximately $4.1 million. A breakdown of this forecast is provided below:

Table 71: Loss on disposal costs by category (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Net book value of disposed assets	1,504	5,503	2,563	1,150	1,226	5,356
Asset removal costs	-	-	-	-	-	1,182
Disposal proceeds	(612)	(2,930)	(1,319)	(480)	(313)	(1,156)
Auction fees and expenses	10	7	23	17	12	14
Gain/loss on AFS settlement	-	-	-	-	-	-
	902	2,580	1,267	687	925	5,396

Table 72: Loss on disposal costs by category (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Net book value of disposed assets	6,607	2,691	2,053	2,019	(3,916)	(638)	(672)
Asset removal costs	991	1,681	1,148	2,170	690	(533)	489
Disposal proceeds	(3,997)	(1,463)	(1,415)	(115)	2,534	48	1,348
Auction fees and expenses	33	-	763	-	(33)	763	-
Gain/loss on AFS settlement	-	(841)	(841)	-	(841)	-	841
	3,634	2,068	1,708	4,074	(1,566)	(360)	2,006

As is evident in the table above, the net book value of the disposed assets, which encompasses much of the costs associated with the loss on disposal of capital assets, tends to vary from year to year.

In 2012, the largest disposals related to partial asset disposals of the Cat Arm dam, Cat Arm road, Black Tickle Diesel Plant, Happy Valley North Plant, and the retirement of distribution poles. In 2012 Hydro created a general ledger account to separately identify capital asset removal costs. In 2012, removal costs of $1,182,000 were expensed, relating primarily to voltage conversion in Labrador and upgrade of Fuel Storage in St. Lewis.

Actual loss on disposal for 2013 totalled $3,634,000. The disposals during the year resulted from capital work completed on the restoration of Unit 1, along with the write off of the Holyrood Gas turbine and the disposal of the Labrador Substation, offset by insurance proceeds received.

Loss on disposal is forecast to decrease by approximately $1.6 million in 2014 over 2013 actuals. This decrease is primarily related to a decrease in the net book value of disposed assets of $3.9 million and an decrease in disposal proceeds of $2.5 million. According to Hydro, the decrease in net book value of disposed assets is due to the failure and subsequent disposal related to the Unit #1 in Holyrood in 2013 as discussed above. Disposal proceeds are forecast to increase primarily due to the insurance proceeds relating to Unit #1 in Holyrood that was damaged. The amount of insurance proceeds relating to this unit was approximately $3.4 million which is partially offset by 2014 test year insurance proceeds related to the Sunnyside Project.

Loss on disposal is forecast to increase by approximately $2.0 million in 2015 over 2014 forecast. This increase is primarily related to a decrease in disposal proceeds of approximately $1.3 million in 2015 over 2014 forecasts which, according to Hydro, is due to the insurance proceeds forecasted for 2014 relating to the Sunnyside Project and the fact that they had no reason to forecast receipt of insurance proceeds in 2015.

Other Cost Categories

In addition to the various categories of expenses commented on above, the other categories of operating expenses by breakdown were also analysed for any unusual variances.

Table 73: Other cost categories (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Insurance	1,703	1,783	1,937	1,960	1,965	2,109
Transportation	2,776	3,046	3,038	3,056	3,377	3,600
Office Supplies	2,262	2,182	2,161	2,100	2,307	2,230
Bldg. rental and maint.	1,234	1,078	1,145	1,170	1,172	1,027
Travel	2,942	2,854	2,910	2,755	2,977	2,979
Equipment rentals	1,082	1,493	1,721	1,738	1,636	1,699
	11,999	12,436	12,912	12,779	13,434	13,644

Table 74: Other cost categories (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Insurance	2,422	2,689	2,579	2,607	267	(110)	(82)
Transportation	3,578	3,832	3,785	3,545	254	(47)	(287)
Office Supplies	2,595	2,629	2,392	2,804	34	(237)	175
Bldg. rental and maint.	1,186	1,149	1,228	1,217	(37)	79	68
Travel	3,338	3,710	3,208	3,717	372	(502)	7
Equipment rentals	1,877	1,877	2,017	3,066	-	140	1,189
	14,996	15,886	15,209	16,956	890	(677)	1,070

These expenses are forecast to increase by approximately $1.1 million or 6.7% in 2015 over 2014 forecast. The biggest variances relate to transportation and equipment rentals. Transportation is forecast to decrease by $287,000. According to Hydro, this is due to a savings in expenses associated with aircraft costs due to its anticipated reduction in rates from a new contract. Equipment rentals are forecast to increase by $1.2 million. According to Hydro, this is due to $1.0 million in expenses associated with the Black Start diesel unit in Holyrood. The full amount of the rental was deferred in 2014, however in 2015 Hydro proposed to defer and amortize these costs over a five year period beginning in 2015 with the net amortization expense being $1.0 million in 2015. The additional $0.2 million relates to equipment rentals across all regulated operation departments.

The actual 2014 amount for total other cost categories decreased by $677,000 over the 2014 forecast. This is primarily due to a decrease in travel expenses of $502,000. According to Hydro, this is due to the Project Execution and Technical Services division costs decreasing by $0.2 million due to operating cost savings and increased activity associated with the 2014 capital program, the HROE divisions costs decreasing by $0.1 million due to fewer apprentices hired than forecast resulting in lower travel costs and the Finance divisions costs decreasing by $0.1 due to less travel than anticipated.

Cost Recoveries

Cost recoveries are forecast to decrease from $9.6 million in 2014 forecast, to $7.1 million in 2015 forecast. The breakdown of cost recoveries and by division is as follows:

Table 75: Cost recoveries by division (2007 – 2012)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012
Executive Leadership & Assoc.	(9)	(2)	-	-	-	-
Human Resources & Org. Effect.	(48)	(35)	(57)	(956)	(886)	(1,027)
Finance/CFO	(1,177)	(1,233)	(2,094)	(2,476)	(2,858)	(4,572)
Project Execution & Tech Services	-	-	-	(19)	-	-
Regulated Operations	(156)	(545)	(2,039)	(883)	(706)	(887)
Corporate Relations	-	-	-	(414)	(748)	(1,388)
	(1,390)	(1,815)	(4,190)	(4,748)	(5,198)	(7,874)

Table 76: Cost recoveries by division (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Executive Leadership & Assoc.	-	-	-	-	-	-	-
Human Resources & Org. Effect.	(1,366)	(1,653)	(1,417)	(1,258)	(287)	236	395
Finance/CFO	(4,807)	(4,465)	(5,448)	(4,494)	342	(983)	(29)
Project Execution & Tech Services	(695)	-	-	-	695	-	-
Regulated Operations	(794)	(1,130)	(1,490)	(621)	(336)	(360)	509
Corporate Relations	(1,449)	(2,375)	(2,542)	(696)	(926)	(167)	1,679
System Operations	-	-	(3)	-	-	(3)	-
	(9,111)	(9,623)	(10,900)	(7,069)	(512)	(1,277)	2,554

Actual 2014 cost recoveries in the Finance/CFO division increased by $1.0 million compared to the 2014 test year. According to Hydro, this is primarily due to increases in administrative fees in information systems and increased recoveries of fixed charge. Administrative fees are discussed in the Cost Allocations section of our report.

Cost recoveries in the Corporate Relations division are forecasted to decrease by $1.7 million in 2015 compared to the 2014 test year. According to Hydro, this is primarily due to CDM Program related costs that came from an uptake in the 2014 industrial program. It is also due to the Isolated System's Community Program that was not forecasted in 2015.

The breakdown of cost recoveries by nature for 2013 and 2014 actual in comparison to 2014 test year and 2015 test year is as follows:

Table 77: Cost recoveries by nature (2013 – 2014 and test years 2014 and 2015)

(000)'s	Actuals 2013	Forecast 2014	Actuals 2014	Forecast 2015	Variance '14F-'13	Variance '14A-'14F	Variance '15F-'14F
Churchill Falls	(1,594)	(1,820)	(1,656)	(1,780)	(226)	164	40
External	(1,643)	(1,479)	(1,708)	(470)	164	(229)	1,009
Intercompany Admin Fee	(3,999)	(3,810)	(4,561)	(3,874)	189	(751)	(64)
CDM Program Cost Deferral	(1,449)	(2,376)	(2,430)	(695)	(927)	(54)	1,681
Fixed Charge (Recovery)	(410)	(130)	(533)	(250)	280	(403)	(120)
Intercompany Vehicle Charge (Recovery)	(16)	(8)	(12)	-	8	(4)	8
	(9,111)	(9,623)	(10,900)	(7,069)	(512)	(1,277)	2,554

Cost recoveries for CDM Program cost deferral were forecast to increase by $0.9 million in 2014 compared to 2013 actuals. According to Hydro, this is primarily due to an uptake in the industrial program in 2014.

Actual cost recoveries in 2014 increased by $1.3 million compared to the 2014 test year. This was primarily due to increases in intercompany administration fees and fixed charge (recovery). According to Hydro, the $0.8 million increase in intercompany administration fees is primarily due to increases in administrative fees in information systems and the $0.4 million increase in fixed charge (recovery) is primarily due to increased recoveries.

External cost recoveries are forecast to decrease by $1.0 million in 2015 compared to the 2014 test year. According to Hydro, this is primarily due to government funding for the apprenticeship program within the Human Resources division in 2014 and a network services contract billing in 2014.

Cost Allocations

We reviewed Hydro's methodology relating to the procedures the Company has in place to allocate costs between regulated and non-regulated operations. We also reviewed how costs are allocated between shared services.

All non-regulated operations are reported to the Corporate Controller and the Treasurer who ensure that business units, and if applicable, work orders, are set up to track costs. Intercompany salary and benefits charged to and from Nalcor Energy and its subsidiaries are captured in the JD Edwards integrated suite of applications and a Lotus Notes Time Reporting application. These costs are recharged through the cost account '6014 – intercompany salaries' in the appropriate business units.

The Application did not include forecast amounts for non-regulated expenses. Forecasts were only provided for regulated expenses.

The following is a summary of non-regulated activities/costs /business units of the Company as filed in Exhibit 7 of the Application:

Subsidiaries

- Churchill Falls (Labrador) Corporation– BU#1958: Services from Hydro to CF (L) Co are rendered according to a services agreement dated January 1, 2010. According to the services agreement, all costs are charged according to Hydro's bill rates, fixed charge rate and an allocation of its intercompany administration fee. This is consistent with Nalcor's intercompany transaction costing methodology as filed in Exhibit 8 of the Application. In addition, prior to December 15 each calendar year, Hydro will provide a list of services to be provided, as well as an estimate of costs to be recovered through monthly billing. Billings are adjusted after actual costs for the year have been determined to the satisfaction of both parties.

- Lower Churchill Development Corporation Limited –BU#1953: This corporation is mainly inactive.

Business units in Hydro

- Export Sales – BU# 1950: Hydro purchases recall power and energy through an agreement with Churchill Falls. Surplus power is sold by Hydro to external markets. Systems Operations allocates the power purchase costs. All revenue and expenses are captured in Business Unit (BU) 1950 and excluded from regulated income.

- Supply of Power to the Iron Ore Company of Canada – BU# 1952: The portion of costs associated with IOCC is derived from the Cost-of-Service on the Labrador Interconnected system. Rates charged are based on a negotiated contract which is not approved by the Board. All revenues and expenses are captured in BU 1952 and excluded from regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology as discussed above.

- Natuashish – BU# 1405: This business unit was established to track costs associated with the community of Natuashish on behalf of the federal government, on a cost recovery basis. All costs are charged at bill rates plus overheads to ensure full cost recovery. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology.

- Star Lake – BU# 1970: Hydro operates this plant on behalf of Nalcor who is acting as agent of the Province. All revenues and expenses associated with this activity are captured in BU 1970 and excluded from regulated expenses. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology.

- Exploits - BU # 2125, # 2127 and # 2129: Hydro is operating the Exploits generating facilities on behalf of Nalcor who is acting as an agent for the Province. All revenues and expenses associated with this activity are captured in BU # 2125, # 2127 and #2129 and are excluded from the determination of regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology.

- Ramea Project – BU# 1406: In accordance with P.U. 31 (2007) no costs associated with the project at Ramea will be borne by ratepayers. All revenues and expenses associated with this activity are captured in BU# 1406 and excluded from regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology.

- Conservation Demand Management – BU# 1949: In accordance with P.U. 7 (2008) Hydro will undertake energy conservation initiatives. All revenues and expenses associated with this activity are captured in BU# 1949 and excluded from regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology.

- Cost Recovery Business Units: Hydro maintains a number of cost recovery business units to capture costs incurred by Hydro personnel on behalf of other lines of business, e.g. Lower Churchill Project, Oil and Gas, Bull Arm and Nalcor Energy. All costs associated with these activities are billed monthly to the lines of business and excluded from regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology. The cost recovery units are as follows:

    a. Lower Churchill Project cost recovery – BU# 1961: Prior to 2008, capital job cost #10250 was set up to capture all costs associated with the current Labrador Hydro Project including an allocation of corporate overhead, salary charges and supplier costs. With the corporate restructuring in 2008, the Lower Churchill project construction work in progress assets were transferred to Nalcor;

    b. Oil and Gas cost recovery – BU#1962: This business unit was established to capture costs related to Nalcor's Oil and Gas division which holds and manages oil and gas interests in the Newfoundland and Labrador offshore;

    c. Bull Arm cost recovery – BU#1963: This business unit was established to capture costs related to Nalcor's Bull Arm site; and

d. Nalcor Energy cost recovery – BU#1964: This business unit was established to capture costs related to Hydro costs charged to Nalcor Energy.

- Other Specific Non-Regulated Costs – BU#1955: This business unit has been established to capture various non-regulated costs, including:
    - Contributions and donations
    - Advertising for corporate image building
    - Companion travel costs
    - Bad debt expenses incurred for specific reasons that are designated non-recoverable are excluded from the determination of regulated income

Determination of Billing Rates

Bill rates for Hydro and its related companies are determined on a cost recovery basis designed to cover salary, benefits and vacation. There is no profit margin element to the billing rate. However, charges for external billings do incorporate a profit margin.

According to Hydro, the time sheet policy / guidelines are as follows:

> All Nalcor employees (except CF (L) Co employees) are to prepare weekly time sheets and code all paid hours (i.e. 37.5 or 40 per week) to a work order or to leave. Mandatory and prompt time sheet reporting for all Hydro Place employees was implemented effective Monday, April 19, 2010 (March 2011 outside Hydro Place). Previously, many employees had been required to record exceptional time only (leaves, overtime and charge-out hours). On a go forward basis all employees are required to record all time to a work order or as leave. Employees are responsible to record the 37.5 or 40 hour work week, plus any additional overtime and/or premiums. Time sheets are to be completed and submitted no later than the following week.

The billing rates were developed to include a base wage amount (hourly wage), a variable component and a fixed charge. The Company's billing rate is derived from a base wage amount and a variable component. The fixed charge is a separate charge based on each hour billed.

<u>Variable component</u>

The Company uses a proxy amount of 57% as the basis to determine bill rates which are calculated as follows: total salary costs and benefits (as described below) are divided by total billable hours. Billable hours are available hours less annual leave, training, sick leave, statutory holidays or other time associated with paid leave. The ratio of the bill rate to the hourly rate is applied to the various pay grades to determine the charge out rates of employees. From 2007 to 2009 the rates were determined using total hours. Beginning in 2010, rates were determined using billable hours. In addition, starting in 2011, the rates were determined in aggregate for the Nalcor group of companies excluding CF (L) Co. In Hydro's latest calculation based on a 2012-2014 analysis, a variable component of 68% proxy was determined. The rate has increased from the 57% used in recent years partially due to the pension reform effective January 1, 2015 for the Public Service Pension Plan resulting in increased costs. We have not investigated the impact that the change from a 57% to 68% variable component has on the 2014 and 2015 test year revenue requirements.

The following costs were included in the analysis to determine the variable component:

Benefits

- Fringe benefit costs, e.g. CPP, EI, Public Service Pension Plan, Group Money Purchase Plan, Prior Service Matched PSPP, WHSCC.
- Insurances, e.g. Life, A D&D, Medical, Dental.
- Company costs, e.g. EE future benefits, payroll taxes, bonus, performance contracts, signing bonus.

Leaves

- Annual leave, medical travel and appointments, sick leave, training hours, floaters, family leave, compassion leave, jury duty, statutory holiday, union leave, banked overtime.

Fixed Charge

Effective October 1, 2009 the Company included a fixed charge for time charged to entities. The fixed charge was determined to be $80 per day for all Nalcor employees, or $10.67 per hour based on a 7.5 hour day for 2009-2011. In 2012, 2013, 2014 forecast and 2015 forecast, the fixed charge was determined to be $98 per day or $13.10 per hour based on a 7.5 hour day. The fixed charge component included the following costs in its analysis:

- *Hydro Place costs* e.g. Heat & Light, insurance, maintenance, reception, depreciation and interest.
- *Common Services* e.g. IT services such as software, servers & help desk, HR services such as payroll, recruitment, health, safety.
- *Employee related costs* e.g. Telephone & Fax, books & subscriptions, training, membership and dues, conferences, training.

According to Hydro, the fixed charge recovery is booked to account for the additional cost of having an employee available for service beyond salary and benefits. The fixed charge recovers costs originally charged in the administration fee allocation as well as other employee related costs described above. The fixed charge for Hydro is recorded in business unit # 2003 NLH Controller Dept under Account # 7141 'intercompany fixed charge' and is grouped under cost recoveries. The fixed charges netted to credits (i.e. recovery) of $532,670 in 2014, $130,240 for 2014 forecast and $250,000 for 2015 forecast.

Common Service Costs Allocation

Certain departments based in Hydro provide common services to various lines of business of Nalcor. Hydro recovers costs incurred related to these common services through an administration fee.

The following table provides a summary of the intercompany administration fee and cost recoveries charged in Hydro to Nalcor's various lines of business and CF (L) Co for the 2014 and 2015 test years with comparative data for 2012, 2013 and 2014 actuals:

Table 78: Summary of intercompany administration fee and cost recoveries

Cost Recoveries	2012	2013	2014F	2014	2015F	2014F-2013	2014A-2014F	2015F-2014F
Intercompany Administration Fee								
Regulated recovery	$ (3,680,313)	$ (3,999,398)	**$ (3,810,860)**	**$ (4,561,880)**	**$ (3,873,910)**	$ 188,538	$ (751,020)	$ (63,050)
Non-regulated expense (Note 1)	25,152	64,641	**-**	**-**	**-**	N/A	N/A	N/A
	$ (3,655,161)	$ (3,934,757)	**$ (3,810,860)**	**$ (4,561,880)**	**$ (3,873,910)**	$ 188,538	$ (751,020)	$ (63,050)
Cost recovery								
CF (L) Co.	$ (1,756,218)	$ (1,594,278)	**$ (1,819,880)**	**$ (1,655,870)**	**$ (1,779,670)**	$ (225,602)	$ 164,010	$ 40,210

Note 1: Non-regulated expense relates to Energy Marketing. Non-regulated expenses were not provided for the forecast years.

Intercompany administration fees for regulated recovery and CF (L) Co. cost recoveries 2014 forecast have decreased by $188,538 and increased by $225,602 respectively compared to 2013. The same items for 2014 actuals have increased by $751,020 and decreased by $164,010 from 2014 forecast. Comparing 2014 and 2015 forecasts, regulated recovery is forecast to increase by $63,050 while CF (L) Co. cost recoveries is forecast to decrease by $40,210. A further breakdown of these costs by department is provided in the table below.

The labour costs relating to the staff working in the common service business units are not charged to the other entities/lines of business since these costs are included in the administration fee calculation.

The following table provides a breakdown of the forecast 2014 and 2015 common costs allocated to each line of business, along with comparative data for 2012, 2013 and 2014:

Table 79: Common cost allocation

Common cost allocation	2012	2013	2014F	2014	2015F	2014F-2013	2014A-2014F	2015F-2014F
Nalcor divisions (Note 1)	$ 3,680,313	$ 3,999,398	**$ 3,810,860**	**$ 4,561,880**	**$ 3,873,910**	$ (188,538)	$ 751,020	$ 63,050
CF (L) Co.	1,756,218	1,594,278	**1,819,880**	**1,655,870**	**1,779,670**	225,602	(164,010)	(40,210)
Hydro Regulated	8,763,626	8,162,624	**8,219,760**	**8,115,650**	**8,324,420**	57,136	(104,110)	104,660
Total common costs allocated	$ 14,200,157	$ 13,756,300	**$13,850,500**	**$14,333,400**	**$13,978,000**	$ 94,200	$ 482,900	$ 127,500

Note 1: Nalcor divisions include Oil and Gas, BullArm, Exploits, Menihek, Lower Churchill Project and Energy Marketing (non-regulated). Disaggregated cost allocations for the Nalcor divisions was not provided for the forecast years.

The following table provides a breakdown of costs by department for the 2014 and 2015 forecast years, along with comparative data for 2011, 2012, 2013 and 2014:

Table 80: Breakdown of costs by department

Total

Department / Costs (000's)	2012	2013	2014F	2014	2015F	2014F-2013	2014-2014F	2015F-2014F
Human Resources	$ 1,688	$ 1,796	$ 1,867	$ 1,889	$ 2,034	$ 71	$ 22	$ 167
Safety and Health	924	993	982	1,040	1,057	(11)	58	75
Information Systems	6,991	6,565	6,607	6,734	6,373	42	127	(234)
Office space and related costs	4,178	3,980	3,964	4,246	4,072	(16)	282	108
Telephone and LAN costs and other	419	422	430	424	442	8	(6)	12
	$ 14,200	**$ 13,756**	**$ 13,850**	**$ 14,333**	**$ 13,978**	**$ 94**	**$ 483**	**$ 128**

Hydro Regulated

	2012	2013	2014F	2014	2015F	2014F-2013	2014-2014F	2015F-2014F
Human Resources	$ 1,051	$ 1,098	$ 1,111	$ 1,133	$ 1,206	$ 13	$ 22	$ 95
Safety and Health	575	607	584	624	627	(23)	40	43
Information Systems	4,482	3,751	4,039	3,595	3,429	288	(444)	(610)
Office space and related costs	2,359	2,410	2,201	2,479	2,772	(209)	278	571
Telephone and LAN costs and other	296	297	284	272	291	(13)	(12)	7
	$ 8,763	**$ 8,163**	**$ 8,219**	**$ 8,103**	**$ 8,325**	**$ 56**	**$ (116)**	**$ 106**

Other Lines of Business (Note 1)

	2012	2013	2014F	2014	2015F	2014F-2013	2014-2014F	2015F-2014F
Human Resources	$ 637	$ 698	$ 756	$ 756	$ 828	$ 58	$ -	$ 72
Safety and Health	349	386	398	416	430	12	18	32
Information Systems	2,509	2,814	2,568	3,139	2,944	(246)	571	376
Office space and related costs	1,819	1,570	1,763	1,767	1,300	193	4	(463)
Telephone and LAN costs and other	123	125	146	152	151	21	6	5
	$ 5,437	**$ 5,593**	**$ 5,631**	**$ 6,230**	**$ 5,653**	**$ 38**	**$ 599**	**$ 22**

Note 1: Other lines of business include Nalcor divisions and CF (L) Co.

Note 2: As Hydro describes in PUB-NLH-169, PUB-NLH-192 and NLH-PUB-200, information systems costs in 2012 are overstated by $706k resulting in an overstatement of administration fee recoveries of $253k. Office space and related costs in 2012 are overstated by $205k resulting in an overstatement of administration recoveries of $89k. Therefore, the total overstatement of administration fee recoveries in 2012 is $342k.

Hydro indicated that the increase of $571,000 in "Office space and related costs" allocated to Hydro Regulated in the 2015 forecast over the 2014 forecast was a result of an increase in square footage occupied by Hydro as well as an increase in common space that was shared among all lines of business (ex. A meeting room becomes accessible as opposed to being reserved for use by a single line of business). The square footage allocated to Hydro Regulated has increased from 84,674 in 2014 test year to 103,822 in the 2015 test year, an increase of 19,148 in square footage.

The allocation of costs related to Information Systems for Hydro Regulated was higher in the 2014 forecast compared to both 2014 actuals and the 2015 forecast, which were fairly consistent. The change is driven by a change in the number of Total Average Users used to determine the cost per user. The 2014 forecast allocated costs based on 1,516 total average users, while the users for 2014 actual and 2015 forecast were 1,864 and 1,896 respectively. When asked to comment on the discrepancy between 2014 forecast and both 2014 actuals and 2015 forecast, Hydro stated that the 2014 test year was determined using allocators in the 2014 budget and 2014 actual and 2015 test year allocators were based on the latest information available.

Recovery of common costs in 2014 actual was $599,000 higher than 2014 forecast. A higher recovery of common costs, all else being equal, would reduce overall expenses and therefore the revenue requirement.

According to Hydro, the department/cost included in the determination of the administrative fee charged, along with the allocation basis, is summarized in the following table:

Table 81: Allocation basis of administration fee

Department/ Costs	Allocation Basis
Human Resources	FTE
Safety and Health	FTE
Information Systems	Average Users
Office space and related costs	Square footage
Telephone and LAN costs	Average Users

We address each of the departments/costs allocations in turn.

<u>Human Resources</u>

The Human Resources department is responsible for the administration and coordination of all employee related services. Operating costs incurred in providing Human Resources services are allocated to the lines of business based on a per full time equivalent ("FTE") basis. The 2014 and 2015 forecast cost per FTE allocated to lines of business for Human Resources are $1,251 and $1,263 respectively per FTE (2014 actual - $1,357, 2013 actual - $1,346).

<u>Safety and Health</u>

The Safety and Health department is responsible for occupational health services including coordinating corporate efforts with regard to employee safety, wellness, disability and sick leave management, and medical screening. Operating costs incurred in providing Safety and Health services are allocated to the lines of business on a per FTE basis. The 2014 and 2015 forecast cost per FTE allocated to lines of business for Human Resources are $658 and $657 respectively per FTE (2014 actual - $747, 2013 actual - $745).

<u>Information Systems</u>

The Information Systems ("IS") department is responsible for providing assistance and support in the areas of Software Applications, Planning and Integration and Business Solutions, maintenance and administration of the corporate wide computer infrastructure and network, and provides technical support. Operating costs incurred in providing IS services are allocated to the lines of business on an average user basis. Depreciation expense and a return on rate base at the weighted average cost of capital ("WACC") for costs capitalized such as servers and software are allocated to each line of business on an average user basis. Costs specific to a particular line of business are charged to that line of business and are excluded from the determination of shared costs. The 2014 and 2015 forecast cost per user allocated to lines of business for IS are $4,360 and $3,362 respectively per user (2014 actual - $3,612, 2013 actual - $4,042).

Office Space

Each line of business occupying floor space at Hydro Place is charged a rental charge. The square footage rental rate reflects the average annual capital and operating cost for Hydro Place as determined by the following formula:

> Rental Rate = Hydro Place operating costs + return on rate base + annual depreciation / (divided by) Hydro Place total square footage.

According to Hydro, the cost based rate includes the following expenses for Hydro Place:

- Annual depreciation for all common assets
- System Equipment Maintenance and operating projects
- Expenses relating to salaries, fringe benefits, group insurance and employee future benefits for Office Services, Building Maintenance and Transportation
- Heat & Light
- Office Supplies
- Postage
- Safety Supplies
- Consulting expenses related to Hydro Place
- Security Card Maintenance Contract
- Return on Rate base at WACC for all common assets

The 2014 and 2015 forecast cost per square footage rental rate is $25.99 and $26.70 respectively (2014 actual - $27.84, 2013 actual - $26.10).

Telephone Infrastructure (PBX) Costs

All lines of business are charged a share of Telephone Infrastructure (PBX) costs including long distance charges. The Local Area Network (LAN) costs provided by Network Services are divided by the total number of LAN ports to derive a cost per user. The telephone costs provided by Network Services are divided by the number of telephone, fax, and modem lines to derive a cost per telephone per user. The average number of users is the factor used for the allocated costs per line of business. For the 2014 and 2015 forecast the cost per user allocated to lines of business for telephone and LAN costs was $508 and $521 respectively per user (2014 actual - $433, 2013 actual - $497).

The 2014 allocations for Human Resource, Safety and Health, and Information Systems are based on actual costs and would therefore be 'trued up' at year end. However, the PBX and LAN allocations are based on budget costs and there is no 'true up' adjustment on these allocations to reflect actual costs. The office space rental charge would be based on a cost recovery rate set for the year.

Based on our understanding of the methodology used by Hydro, we conclude that cost allocations are in accordance with Intercompany Transaction Costing Guidelines as filed in Exhibit 8 of the Application.

Rate Stabilization Plan

History of the Rate Stabilization Plan

The Rate Stabilization Plan ("RSP") or ("the Plan") was established for Newfoundland and Labrador Hydro ("Hydro") effective January 1, 1986. The original objective of the RSP was to provide rate stability to customers by providing a mechanism to manage volatility in Hydro's revenue requirements due to events beyond their immediate control. When the RSP was implemented it provided for adjustments to recover differences between the forecast test year costs used to set rates and the actual costs attributable to:

1. differences in the price of No.6 Fuel;
2. variations in hydraulic production; and
3. variations in load.

Since the original inception, the RSP has been modified on several occasions. A complete historical review of the RSP "Board of Commissioners of Public Utilities – Historical Review of the Rate Stabilization Plan of Newfoundland and Labrador Hydro - January 1, 1986 to December 31, 2009 (updated to December 31, 2014)" will be released upon completion.

Rate Stabilization Plan – 2014 Test Year

Included in the Finance section of Hydro's GRA filing, Schedule 1 (page 7 of 11), the RSP balance at the end of December 2014 is forecast to be a balance owing to ratepayers of $197,028,000. The breakdown of the components included in the Plan as indicated in Schedule 1 (page 7 of 11) is as follows:

Component	($000s)
Hydraulic balance	$ 11,505
Utility balance	25,730
Industrial balance	(8,347)
Utility Segregated Load Variation	(721)
Industrial Segregated Load Variation	33,816
Utility Surplus	124,014
Industrial Surplus	11,031
Total balance owing	$ 197,028

Note: The Segregated Load Variation on Schedule 1(page 7 of 11) is $33.095 million. The allocation Between Utility and Industrial was obtained from the supporting schedules provided by Hydro.

The various inputs included in the Plan for the 2014 test year are based on the 2007 test year cost of service. The Plan also includes the actual results for the period January 1, 2014 to May 31, 2014. The period from June 1, 2014 to December 31, 2014 is based on forecast hydrology, fuel prices and load. However, the RSP adjustment rate for Newfoundland Power ("the utility") is based on Board approved rates for the entire year.

Hydro also included an adjustment of $45,921,000 in the Hydraulic Production Variation Account of the RSP as of December 31, 2014. This adjustment relates to the Application filed by Hydro on November 28, 2014, for approval, among other items, to establish a deferral account and transfer the 2014 forecast revenue deficiency of $45.9 million to the deferral account. Hydro also proposed to use the credit balance in the RSP Hydraulic Production Variation Account at December 31, 2014 to provide recovery of the 2014 revenue deficiency.

On December 24, 2014, the Board issued P.U. 58 (2014). In this Order, the Board did approve the deferral of the $45.9 million, however the Board did not approve the proposed use of the credit balance in the RSP Hydraulic Variation Account balance to provide recovery of the $45.9 million forecast revenue deficiency.

Rate Stabilization Plan – 2014 Actual

On February 16, 2015, Hydro filed the actual results for the RSP as of December 31, 2014. The RSP as of December 31, 2014 has a balance of $245,954,000 owing to ratepayers. The breakdown of the components included in the Plan is as follows:

Component	($000s)
Hydraulic balance	$ 43,358
Utility balance	39,004
Industrial balance	(6,775)
Utility Segregated Load Variation	(520)
Industrial Segregated Load Variation	35,980
Utility RSP Surplus	124,014
Industrial RSP Surplus	10,893
Total balance owing	$ 245,954

The balance in the RSP above is $48.9 million higher than the RSP balance of $197,028,000 included in the amended GRA for the 2014 test year. This increase is a result of a number of factors:

- The most significant factor contributing to the increased balance is the Board's denial of the use of the credit balance in the Hydraulic Variation Account to recover the $45.9 million forecast revenue deficiency noted above. This increase has been partially offset by the decrease in the actual net hydraulic production as of December 31, 2014 of 38,064,633 kWh in comparison to the 2014 test year. These factors resulted in an increase of $42,336,000 in the Hydraulic Variation component of the Plan (before the annual allocation) in comparison to the 2014 test year.

- The actual quantity of No. 6 fuel used in 2014 was 83,329 barrels lower than the amount included in the 2014 test year and the actual average No. 6 fuel cost was $1.05/bbl. lower than the 2014 test year cost ($109.59/bbl. vs. $108.54/bbl.). This resulted in a decrease of $6,729,000 in the Fuel Variation component of the Plan in comparison to the 2014 test year. As a result of this decrease, the balances owing to the Utility customer increased and the amount owing from the Industrial customers decreased in comparison to the 2014 test year.

- The actual sales in 2014 to the Utility customer were 110,759,219 kWh lower than the forecast sales included in the 2014 test year. This resulted in an increase in the load variation owing to the Utility customer of $202,910 in comparison to the 2014 test year.

- The actual sales in 2014 to the Industrial customers were 41,549,659 kWh lower than the forecast sales included in the 2014 test year. This resulted in an increase in the load variation owing to the Industrial customers of $2,124,804 in comparison to the 2014 test year.

- The remaining difference is due to the amount recovered from the Utility customer via the RSP adjustment being lower as result of lower sales in comparison to the 2014 test year and the change in finance charges as a result of the changing balances.

Table 82: 2014 RSP Test Year and Actual balances

(000)'s	RSP 31-Dec-14 Test Year	RSP 31-Dec-14 Actual	Variance
Hydraulic balance	$ 11,505	$ 43,358	$ 31,853
Utility balance	25,730	39,004	13,274
Industrial balance	(8,347)	(6,775)	1,572
Utility Segregated Load Variation	(721)	(520)	201
Industrial Segrated Load Variation	33,816	35,980	2,164
Utility Surplus	124,014	124,014	-
Industrial Surplus	11,031	10,893	(138)
Total balance owing	$ 197,028	$ 245,954	$ 48,926

Highlights of the RSP for 2014 include:

- Favourable hydraulic conditions contributed to higher hydraulic production relative to the cost of service production resulting in fuel savings of $18 million. Actual net hydraulic production in 2014 was 4,670.7 GWh in comparison to the cost of service (2007) net hydraulic production of 4,472.1 GWh. The net hydraulic production included in the 2014 test year is 4,708.8 GWh.

- The average No. 6 fuel price in 2014 was approximately $108.54 per barrel in comparison to the cost of service (2007) price of $55.47 per barrel which resulted in a fuel variation of approximately $119.7 million due from customers. The 2014 test year average No. 6 fuel price used in the RSP is $109.59 per barrel.

The tables below provide a breakdown of the activity in the RSP for 2014 as well as a continuity of the various component balances.

Table 83: 2014 RSP activity

(000)'s	Hydraulic Variation	Fuel Variation	Load Variation	Rural Rate Alteration	Total
Hydraulic balance	$ (18,010)	$ -	$ -	$ -	$ (18,010)
Utility customers		111,760	-	(8,076)	103,684
Industrial customers		6,993	-	-	6,993
Segregated load variation			(25,713)		(25,713)
Labrador Interconnected	142				142
Net change 2014	$ (17,868)	$ 118,753	$ (25,713)	$ (8,076)	$ 67,096

Table 84: Continuity of the various RSP component balances

(000)'s	Balance Beginning of Year	Current Variation	Current Interest	Hydraulic Allocation	Refund (Recovery)	Balance December 31st 2014
Hydraulic balance	$ (39,801)	$ (18,010)	$ (4,391)	$ 18,844	$ -	$ (43,358)
Industrial customers	566	6,993	317	(1,101)	-	6,775
Utility customers	(80,174)	103,684	(2,901)	(17,601)	(42,013)	(39,005)
Segregated load variation	(8,200)	(25,713)	(1,547)			(35,460)
Utility Surplus	(115,330)		(8,683)			(124,013)
Industrial Surplus	(10,858)		(791)		756	(10,893)
Labrador Interconnected (1)	-	142		(142)		-
Net change	$ (253,797)	$ 67,096	$ (17,996)	$ -	$ (41,257)	$ (245,954)

[1] The amount is written off to net income.

Newfoundland Power RSP Surplus

Hydro was directed in the Orders of Council OC2013-089 and OC2013-207 dated April 4, 2013 and July 16, 2013 respectively, that during the GRA process the Company shall file a Rate Stabilization Plan surplus refund plan to ratepayers, excluding Island Industrial customers.

In compliance with the Order in Council, Hydro filed an application on October 31, 2013, with a minor amendment filed on November 7, 2013, to address the Newfoundland Power RSP Surplus balance. As of December 31, 2013, the balance of the Newfoundland Power RSP Surplus plan has accumulated to $115,330,000. This balance is made up of the $112,573,000 of the accumulated load variation from January 1, 2007 to August 31, 2013 ($161,573,000 -$49,000,000 to Industrial Customer plan), and monthly finance charges totalling $2,760,000, using an annual WACC of 7.529% (2007 test year WACC).

The Board issued P.U.9 (2014) on April 9, 2014 in response to this application. In this Order, the Board ordered that:

> *"The Newfoundland Power Rate Stabilization Plan Surplus shall be refunded to all ratepayers, with the exception of the Island Industrial customers in the form of direct payment or rebate and in a manner to be approved by the Board"*

In its Order the Board also indicated that "all ratepayers, with the exception of the Island Industrial customers", will include Newfoundland Power customers and customers on each of Hydro's systems, including the Rural Island Interconnected, Island Isolated, Labrador Isolated, L'Anse au Loup, and the Labrador Interconnected.

The Order also indicated that Hydro has advised the Board that it is waiting on a ruling from the CRA on the HST treatment of the refund. It is also noted in the Order that the Board expects Hydro, Newfoundland Power and the Consumer Advocate to work jointly to determine a reasonable and appropriate approach in relation to the refund, that is consistent with the direction of Orders in Counsel, and file a consensus proposal with the Board for its consideration.

Since filing this Order, the Consumer Advocate and Hydro filed an appeal with the Supreme Court Newfoundland and Labrador Court of Appeal (the "Court of Appeal"), arguing that Labrador ratepayers should not receive a refund from this Surplus account because they were not the ratepayers whose rates were influenced by Holyrood and who had overpaid.

On May 6, 2015, the Court issued its decision. The Court of Appeal ruled that electrical customers in Labrador and those on the Island Isolated Systems are not entitled to share in the funds that would be refunded from the Surplus account. Any other issues regarding the refund were referred back to the Board for its consideration.

As indicated in Table 82 above, as of December 31, 2014 the Newfoundland Power RSP Surplus account has accumulated to $124,013,000.

Summary of Hydro Proposals included in the 2013 Amended General Rate Application

In the 2013 Amended GRA, (Section 4 – page 4.38), Hydro proposed the following changes to the RSP in 2015:

- "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 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;

- 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."

Rate Stabilization Plan – 2015 Test Year

Included in the Finance section of Hydro's Amended GRA filing, Schedule 1 (page 7 of 11), the RSP balance at the end of December 2015 is forecast to be a balance owing to ratepayers of $184,240,000 The breakdown of the components included in the Plan as indicated in Schedule 1 (page 7 of 11) is as follows:

Component	($000s)
Hydraulic balance	$ 8,629
Utility balance	4,601
Industrial balance	(8,592)
Utility RSP Surplus	132,468
Industrial RSP Surplus	11,783
Utility Segregated Load Variation	(770)
Industrial Segregated Load Variation	36,121
Total balance owing	$ 184,240

Note: The Segregated Load Variation on Schedule 1(page 7 of 11) is $35.351 million. The allocation Between Utility and Industrial was obtained from the supporting schedules provided by Hydro.

The preparation of the Plan included in the GRA was based on various inputs in the Plan being rebased at 2015 test year values. Therefore activity within the RSP for the 2015 test year would be minimal as there would be no variations; the test year and "actual" would be the same. The rebased inputs of the plan for the 2015 test year are as follows:

- the hydraulic production is forecast to be 4,603.6 GWh
- the Holyrood No. 6 fuel conversion factor is forecast to be 603 kWh/bbl
- Average No. 6 fuel purchase price per barrel is forecast to be $93.32/bbl
- Firm energy sales to Newfoundland Power is forecast to be 5,924,100,000 kWh
- Firm energy sales to the Industrial Customers is forecast to be 621,400,000 kWh
- The interest rate used within the Plan is based on the forecast WACC of 6.82%
- The RSP adjustment rate used to determine the payment (refund) to the customer does not include a fuel rider for 2015.

Based on our review, the opening balances in the 2015 test year RSP included in the Application are the closing balances noted previously for the 2014 Test Year RSP. As noted earlier, the 2014 Test Year included a $45.9 million adjustment to the Hydraulic Variation Account balance as of December 31, 2014 to provide for the recovery of the 2014 forecast revenue deficiency, which was not approved by the Board in accordance with P.U. 58 (2014). The 2015 test year RSP balance would also not take into consideration the actual 2014 RSP results that were discussed earlier.

In response to PUB-NLH-482, Hydro provided an update to the 2015 test year RSP to reflect the actual 2014 closing balances of the RSP. Based on this update the RSP balance at the end of the 2015 test year is forecast to be a balance owing to rate payers of $229,931,000. The breakdown of the components included in the Plan as indicated in PUB-NLH-482, Attachment 1 (page 7 of 7) are as follows:

Component	($000s)
Hydraulic balance	$ 32,519
Utility balance	21,446
Industrial balance	(6,014)
Utility RSP Surplus	132,468
Industrial RSP Surplus	11,635
Utility Segregated Load Variation	(555)
Industrial Segregated Load Variation	38,432
Total balance owing	$ 229,931

The difference between this update and the balance in the Application is an increase in the balance owing of $45,691 million, which is primarily the result of the Board not approving the $45.9 million adjustment to the credit balance in the RSP Hydraulic Variation Account to offset the 2014 revenue shortfall.

Review of the RSP Components

In our review of the balances of the various components of the 2015 Test Year RSP, the rebasing of the components noted above were taken into consideration.

Hydraulic Balance

As indicated in the RSP rules, each year the following occurs:

- 25% of the balance in the Plan at the end of the year as a result of the variation between the cost of service (test year) hydraulic production and the actual hydraulic production and 100% of the finance charges within the Hydraulic component throughout the year is allocated to the customers;
- 75% of the plan remains as the Hydraulic Balance.

As indicated previously, in the test year forecast there will be no hydraulic production variations as the "actual" and the test year will be the same. Therefore, the only activity happening throughout the 2015 test year in this component of the Plan are the finance charges.

		(000s)
Opening balance, January 1, 2014	$	43,359
Finance charges @ 6.82%		2,955
		46,314
Less: Allocation to customers		
-25% of balance before finance charges		(10,840)
-100% of finance charges		(2,955)
		(13,795)
Closing balance, December 31, 2015	$	32,519

- The amount noted above to be allocated to customers is allocated to the utility, industrial customers and rural customers based on the 12 month forecast kWh hours sold.
- The rural balance is then reallocated to the utility customer and the Labrador Interconnected using the following percentages – 96.2% to the utility and 3.8% to Labrador Interconnected. These percentages are determined in the 2015 test year cost of service study. It is the same portion that the Rural Deficit is allocated in the cost of service study. The proposed allocation percentages have changed in comparison to previous years, which were 89.10% and 10.90% respectively.
- The portion reallocated to the Labrador Interconnected is written off to income by Hydro.

Utility Balance

The changes that would impact the Utility Balance in a test year forecast would be:

- the finance charges;
- the adjustments relating to the RSP rate that are in effect during the 2015 test year; and
- the utility's portion of the hydraulic allocation noted above.

Also, in accordance with P.U. 29(2013), the load variation from the Utility and Industrial Customers as of September 1, 2013 will be held in a separate account until its disposition.

		(000s)
Opening balance, January 1, 2015	$	39,005
Finance charges		1,587
Adjustment Jan- June		(18,375)
Adjustment July - Dec		(13,309)
Load variation adjustment		(0)
Hydraulic allocation		12,538
Closing balance, December 31, 2015	$	21,446

Based on our review of the balances noted above, we have verified the following:

- The finance charges are calculated using a forecast annual WACC of 6.82%.
- The adjustment for January, 2015 to June, 2015 is calculated based on 0.551 cents/kWh which is the "Current Plan" portion of the RSP Adjustment Rate that was approved by the Board in P.U.

19(2014). It would not include the fuel rider portion of the rate that was approved in this Order as the fuel rider is set to zero in a test year.

- Hydro is calculating the adjustment for July, 2015 to December, 2015 period using a rate of 0.514 cents/kWh .
- The Hydraulic allocation is based on the test year kWh sales to Newfoundland Power and 96.24% of the amount allocated to the Rural customers.

Industrial Balance

The changes that would impact the Industrial Balance in a test year would be:

- the finance charges;
- the adjustments relating to the RSP rate that are in effect during the 2015 test year; and
- the Industrial Customer's portion of the hydraulic allocation noted in the Hydraulic Plan.

As previous noted, in accordance with P.U. 29(2013), the load variation from the Utility and Industrial Customers as of September 1, 2013 will be held in a separate account until its disposition.

Also, in accordance with P.U. 40(2013), the RSP adjustment rate of $nil will continue on an interim basis until a further Order of the Board.

		(000s)
Opening balance, January 1, 2015	$	(6,775)
Finance charges		(462)
Adjustments (Jan- Dec)		0
Hydraulic allocation		1,223
Closing balance, December 31, 2015	$	(6,014)

Based on our review of the balances noted above, we have verified the following:

- The finance charges are calculated using a forecast annual WACC of 6.82%.
- The adjustment for January, 2015 to December, 2015 is calculated using the RSP adjustment rate of $Nil cents per kWh that was set in accordance with P.U. 40(2013) and will continue on an interim basis until a further Order of the Board.
- The Hydraulic allocation is based on the test year kWh sales to Industrial Customers.

As previously noted in the summary of Hydro's proposals, one of Hydro's proposed modifications for the 2015 test year was that the recovery of the December 31, 2014 Industrial Customer Current RSP balance be recovered over a two year amortization period starting January 1, 2015. The recovery of the 2014 balance of $6.775 million in accordance with this proposal has not been reflected in the schedules of the 2015 test year RSP activity included in PUB-NLH-482.

However, subsequent to filing the 2013 Amended GRA, on January 28, 2015 Hydro filed an application for the approval of, among other things, customer electricity rates for 2015 on an interim basis. On May 8, 2015, the Board issued P.U. 14(2015) in response to this application. Included in this Order, the Board approved effective July 1, 2015, changes to the RSP rules to allow a transfer from the Industrial Customer RSP Surplus component to fund the full amount of the December 31, 2014 Industrial Customer Current RSP balance.

Therefore, based on this Order, the 2014 balance of $6.775 million will be fully recovered from the Industrial Customer RSP Surplus component and the two year recovery will no longer be required.

The impact from P.U. 14(2015) has not been taken into consideration in the 2015 test year RSP reviewed in this report.

Segregated Load Balances

This component of the RSP is the result of Board Order P.U. 29 (2013) in which the Board ordered that the load variation from the Industrial and Utility Customers as of September 1, 2013 be held in a separate account until its disposition. The only changes that would impact this account during the 2015 test year would be the addition of the finance charges for the year. The finance charges are calculated using a forecast annual WACC of 6.82%.

(000s)	Utility balance	Industrial balance	Total
Opening balance, January 1, 2015	$ (520)	$ 35,980	$35,460
Finance charges	(35)	2,452	2,417
Closing balance, December 31, 2015	$ (555)	$ 38,432	$37,877

As previously noted in Hydro's summary of proposals, in this Application Hydro is proposing 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. The balance in this account represents the load variations that have occurred under the existing methodology since September 1, 2013.

The existing methodology for the allocation of the load variation provides for the net effect of load variation on costs to be assigned to the customer groups that caused the load variation. According to Hydro, the direct assignment approach has been shown to have the potential for rate volatility if customer load requirement are materially different from the forecast Test Year load requirements.

Hydro indicates that the proposed methodology will allocate the net cost effect of load variation on a basis consistent with the method that the fuel price variation is currently allocated among customer groups in the RSP, and the proposed method is also consistent with the cost allocation effects of changes in load in a Test Year Cost of Service Study

This proposal was also included in the July 31, 2013 RSP Application filed by Hydro, and a number of the expert reports filed in relation to this Application addressed the proposed load variation methodology and recommended that the approach be approved if the load variation component is maintained in the RSP.

The balance in this account will remain segregated until a further Order of the Board providing for the disposition of the balance. In the 2013 Amended GRA Application, Hydro is proposing that the balance in this account be allocated based on an energy ratio allocation.

Utility RSP Surplus

As previously discussed in this report, this component of the RSP is the result of Orders in Councils OC2013-089, OC2013-207, and Board Orders P.U. 26(2013) and P.U. 29(2013) in which the Board ordered, in accordance with the Orders in Councils, that the load variation component as of August 31, 2013 be allocated to a Utility RSP Surplus account and an Industrial Customer RSP Surplus account. As a result of these Orders, $112,573,000 was allocated to the Utility RSP Surplus account as of September 1, 2013. Since this time, the only activity recorded in this component of the RSP is the monthly finance charges. The finance charges are calculated using a forecast annual WACC of 6.82%.

		(000s)
Opening balance, January 1, 2015	$	124,014
Finance charges		8,454
Closing balance, December 31, 2015	$	132,468

As previously discussed, the Board's previous order P.U.9 (2014) relating to the disposition of this balance had been appealed by the Consumer Advocate and Hydro and, on May 6, 2015, the Court of Appeal issued its decision. The Court of Appeal ruled that electrical customers in Labrador and those on the island isolated systems are not entitled to share in the funds that would be refunded from the Surplus account. The balance in this account is to be refunded to the ratepayers on the island interconnected system with the exception of the island industrial customers.

Industrial Surplus

As noted above, this component of the RSP is the result of Orders in Councils OC2013-089, OC2013-207, and Board Orders P.U. 26(2013) and P.U. 29(2013) in which the Board ordered, in accordance with the Orders in Councils, that the load variation component as of August 31, 2013 be allocated to a Utility RSP Surplus account and an Industrial Customer RSP Surplus account ("IC RSP Surplus account"). As a result of these Orders, $49,000,000 was allocated to the Industrial RSP Surplus account as of September 1, 2013. The balance of the Industrial Plan on August 31, 2013, after the $160,750,000 (112,573,000+49,000,000) of the accumulated load variation from January 1, 2007 to August 31, 2013 was removed from it, was a balance owing to Hydro of $38,129,000. This balance was offset against the $49,000,000 and the balance of $(10,870,627) was transferred to the RSP Industrial Surplus component.

The directives (OC2013-089 and OC2013-207) from Government ordered that the funding for the three year Island Industrial customer rate phase-in be drawn from the accumulated load variation. In the July 31, 2013 RSP Application, Hydro applied for changes in the RSP rules to implement the phase-in, however, Hydro indicated in CA-NLH-11 that the proposed changes to the RSP rules are not required until the conclusion of the General Rate Application. In P.U. 29(2013), the Board said that at this time they were not going to approve the proposed changes to the RSP rules in relation to the phase-in of rates and allocation of the RSP surplus for Island Industrial customers, including the Teck Resources Limited. It was agreed that Hydro would accumulate the RSP rate for Teck Resources Limited ((1.111) cents/kWh) and segregate the balance from the components of the Industrial Customers RSP balance to be addressed by a future Order of the Board. In P.U. 40(2013) the RSP rules were amended to continue, on an interim basis, with the rate per kWh which was approved in P.U. 29(2013). During 2014, the only activity in this account was the RSP drawdown adjustment rate of 1.111cents/kWh for Teck Resources and the finance charges, however in the schedules supporting the 2015 test year RSP, the drawdown was not calculated and the only activity is the monthly finance charges. The finance charges are calculated using a forecast annual WACC of 6.82%.

		(000s)
Opening balance, January 1, 2015	$	10,893
Finance charges		742
Closing balance, December 31, 2015	$	11,635

As noted above, the directives from Government ordered that the Industrial Customer 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 account. In the Amended GRA Application Hydro is proposing to complete the phase-in of the Industrial Customer base rates by September 1, 2016 by limiting the impact through the use of the IC RSP Surplus balance. The RSP Surplus Credit Adjustment would be reduced for the period September 1, 2015 to August 31, 2016 and eliminated September 1, 2016.

Hydro is proposing that 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. Effective January 1, 2015, Hydro is proposing that the RSP Surplus Credit Adjustment will be set to 85% of each customer's bill increase resulting from the change in base rates. This means that 85% of the customer's monthly bill impact as a result of the new base rates will be recovered from the RSP Surplus account. Effective September 1, 2015, this credit adjustment would be reduced to 35% and on September 1, 2016 the RSP Surplus Credit Adjustment would be set to zero.

However, as previously discussed, subsequent to filing the 2013 Amended GRA, on January 28, 2015 Hydro filed an application for the approval of, among other things, customer electricity rates for 2015 on an interim basis. On May 8, 2015, the Board issued P.U. 14(2015) in response to this application. Included in this Order, the Board approved the following, effective July 1, 2015:

- an interim increase of 10% in the base rate of Industrial customers;

- changes to the RSP rules to allow a transfer from the IC RSP Surplus account and to implement an IC RSP rate so that there is an effective interim increase of 2.7% in Island Industrial customer rates, including Teck; and

- changes to the RSP rules to allow a transfer from the IC RSP Surplus account to fund the full amount of the 2014 year-end Industrial Customer RSP current balance.

As of December 31, 2014, the Industrial Customer RSP Current Account balance owing to Hydro was $6.775 million. As previously noted, this amount will now be fully recovered from the IC RSP Surplus account.

Based on the transfers ordered in P.U. 14 (2015), the proposals noted in the Amended GRA Application for the Industrial Customer rate phase-in period may have to be adjusted.

Key Performance Indicators

Functionally Oriented Financial KPIs

In P.U. 14 (2004), it was ordered that Newfoundland Hydro file with its annual financial report, commencing in 2004 until otherwise directed by the Board, an annual report outlining appropriate historic, current and forecast comparisons of reliability, operating, financial and other key targeted outcomes/measures including the additional KPIs accepted in P.U. 14 (2004), which include the following:

- Corporate operating, maintenance and administrative expense (OM&A) per MWh delivered;
- Generation OM&A per MW installed capacity;
- Generation OM&A per GWh generated;
- Transmission OM&A per transmission circuit km; and
- Distribution OM&A per distribution circuit km.

Hydro has been in compliance with this Board Order and has filed KPI reports with the Board since 2004. However, it has been noted by Hydro in its KPI reports that setting targets for functionally oriented (e.g. generation, transmission) financial KPIs, as identified above, require a Cost of Service (COS) 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.

Hydro has identified targets for functionally oriented financial KPIs only when a Test Year COS study has been available. According to the Company, forecast COS studies are a significant undertaking and are not completed as frequently as would be necessary to report meaningful KPI information. In response to inquiring if Hydro could report target functional KPIs on the basis of the most recent completed COS study, the Company explained that target KPIs based on the most recent COS study are not meaningful KPI information as they would not represent what the Company is actually targeting in a subsequent year. Other KPI targets such as reliability targets are actually set and progress is measured by Hydro. Allocation factors from the Cost of Service Study would vary each year. Load and plant costs, in particular, are significant inputs to the COS study and may change quite significantly from year to year.

Due to the significant effort and cost associated with generating a COS study to set targets for functionally oriented financial KPIs, Hydro requested in their original GRA filing the Board's approval to alter or amend P.U. 14 (2004) so that functionally oriented financial KPIs are not required to be provided on a forecast basis. However, Hydro has since given consideration to this issue based on a report by Mr. Doug Bowman, included in the pre-filed evidence to the amended application, which states that, "it is useful for the Parties and the Board to see how Hydro is performing relative to targets, particularly when Hydro's return on equity is fixed by way of Government directive and that it 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." As a result, Hydro is proposing to continue to provide such information in its annual KPI reports based on the most recent Test Year Cost of Service Study.

Peer Group Benchmarking

The Board in P.U. 8 (2007) directed Hydro to file a report no later than October 31, 2007, updating the progress of the development of an acceptable peer group for financial KPIs as of September 30, 2007. In the report filed by Hydro, two separate peer groups were identified through the United States Federal Energy Regulatory Association (FERC) – one for the generation KPIs and one for the transmission KPIs.

Hydro stated that there was too much variability among the relative generation and transmission statistics of the utilities to arrive at a meaningful single set of peers. According to Hydro, no changes have been made to these acceptable peer groups in the 2014 Annual Report on KPIs, and the Company has not completed a study or report to evaluate any alternatives to its peer groups for its financial KPIs since the initial report that was prepared in accordance with P.U. 8 (2007).

We noted that, included in the Finance Section of the original Application, Chart 3.1 on page 3.8, Hydro references Canadian regulated utilities as Hydro's peers. In discussions with Hydro, we asked if the Company would consider the Canadian regulated utilities referred to in this chart as a more appropriate peer benchmarking group than the US based peer group currently reported in its Annual KPI reporting, and whether this group would be an acceptable peer group for the purpose of benchmarking Hydro's financial KPI's. According to Hydro, based on preliminary discussions with the Canadian Electrical Association ("CEA"), the CEA has indicated that the collection of peer group Canadian Utility KPI data and Canadian Financial KPI data is currently unavailable.

Capital Expenditures

The following table details the actual versus budgeted capital expenditures from 2009 to 2014, and the forecast figures for 2014 and 2015.

Table 85: Comparison of capital expenditures – actual to budget

(000's)

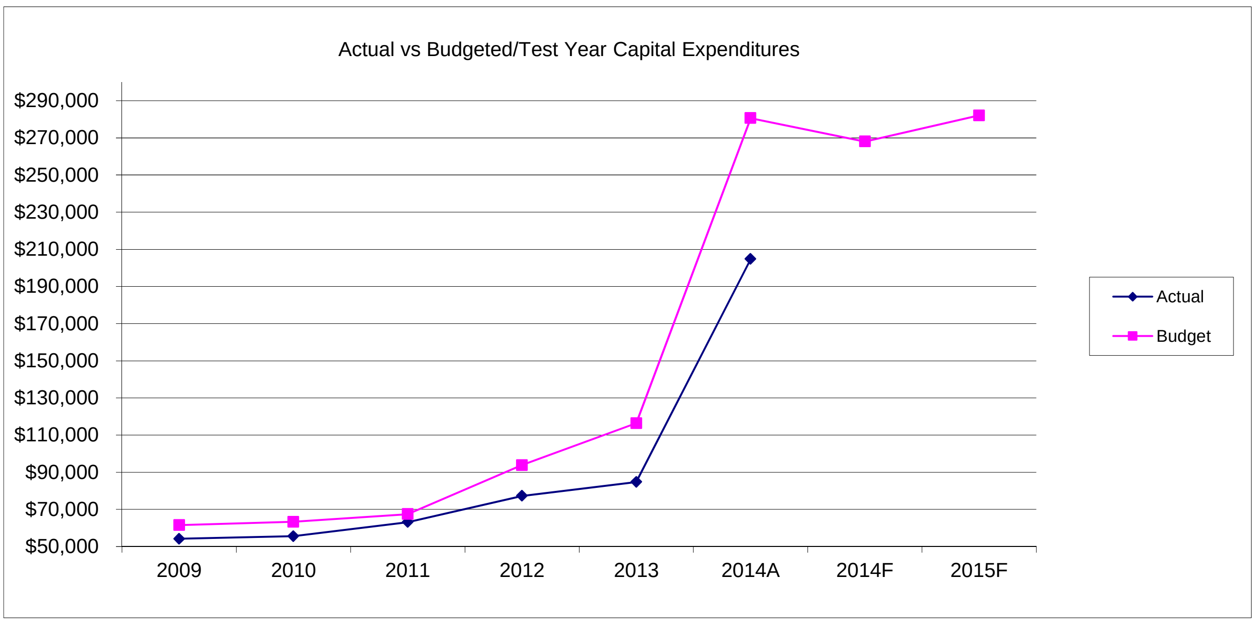
	2009	2010	2011	2012	2013	2014A	2014F	2015F [1]
Actual 2007 - 2014	$ 54,152	$ 55,553	$ 63,116	$ 77,252	$ 84,755	$ 204,728		
Budget	$ 61,544	$ 63,297	$ 67,454	$ 93,840	$ 116,374	$ 280,601	$ 268,023	$ 282,106 [2,3]
Over/Under Budget	-12.01%	-12.23%	-6.43%	-17.68%	-27.17%	-27.04%	N/A	N/A

Note 1: 2014A includes $1.8 million in insurance proceeds relating to the Sunnyside Transformer T1 Replacement.

Note 2: The budget for 2014A is the total of the Company's Board approved capital expenditures in 2014 and is reconciled to the budget for 2014F further in this section.

Note 3: The 2014F and 2015F "budget" figures are the Company's Test Year Forecast for the respective year.

Graph 6: Comparison of capital expenditures – actual to budget



The above graph demonstrates that from 2009 to 2014 the Company has been consistently under budget/forecast on its capital expenditures. According to Capital Budget Application Guideline #1900.6 issued by the Board: "Should the overall variance in any two years exceed 10% of the budgeted total the report should address whether there should be changes to the forecasting or capital budgeting process which should be considered." The Board has had meetings with the Company and has clarified that a 10% variance in either direction should be addressed in discussing the capital budget process. Hydro has provided an explanation as to why the recent variances have occurred in the 2014 Capital Expenditures and Carryover Report.

Based on the information above, the Company's actual expenditures have been under budget every year, ranging from 6.43% under budget in 2011 to 27.17% under budget in 2013.

We have reviewed the significant variances from 2009 to 2013 as part of our annual financial reviews, and our comments on these variances are contained in our annual review reports filed with the Board.

Subsequent to the filing of its 2014 Capital Budget Application, the Company requested and the Board approved the following supplementary 2014 capital expenditures in:

(i) Order P.U. 38 (2013) in the amount of $1,263,400 to ensure black start capability at the Holyrood Thermal Generating Station;

(ii) Order P.U. 16 (2014) to approve the purchase of 100 MW of combustion turbine generation at the Holyrood Thermal Generating Station, while costs and costs recoveries would be addressed in a future Order of the Board;

(iii) Order P.U. 23 (2014) in the amount of $580,000 as a supplementary amount to the Allowance for Unforeseen Items;

(iv) Order P.U. 29 (2014) in the amount of $7,197,800 for the purchase and installation of the Sunnyside T1 transformer and associated equipment, modification to the protection relay system and addition of a 230 kV breaker;

(v) Order P.U. 32 (2014) in the amount of $1,452,500 to replace the T5 transformer at the Western Avalon Terminal Station;

(vi) Order P.U. 33 (2014) in the amount of $3,632,200 for the replacement of all insulators on transmission line TL-201 and 30 insulators on transmission line TL-203;

(vii) Order P.U. 34 (2014) in the amount of $636,700, for 2014, for the replacement of the excitation transformers at the Bay d'Espoir generating station;

(viii) Order P.U. 36 (2014) in the amount of $958,800 to install additional transformer capacity at the Wabush Substation by relocating the transformer from the Quartzite Substation;

(ix) Order P.U. 38 (2014) in the amount of $320,600 to replace an air compressor at the Holyrood Thermal Generating Station;

(x) Order P.U. 45 (2014) in the amount of $608,900, for 2014, to complete the Labrador City Voltage Conversion;

(xi) Order P.U. 46 (2014) in the amount of $491,753 to purchase critical spares for the Holyrood Thermal Generating Station; and

(xii) Order P.U. 53 (2014) in the amount of $2,412,600, for 2014, for the construction of the 230 kV transmission line between the Bay d'Espoir and Western Avalon terminal stations.

In addition to the above Orders of the Board, Order in Council 2014-033 (O.C. 2014-033) approved the construction of a new 230 kV transmission system between Churchill Falls and Labrador West (Labrador

West Transmission Project). The order also exempts this project from the *Electrical Power Control Act, 1994* and the *Public Utilities Act*. The 2014 Capital Budget included $37,484,200 for the Labrador West Transmission Project of which $10,996,000 was spent during the year.

Capital expenditures approved by Board Orders total $226,976,500. In addition, approved expenditures of $37,484,200 were approved by O.C. 2014-033, carryovers from 2013 and earlier projects totalled $15,655,200, and Hydro approved projects of less than $50,000 totalled $485,100, for a total of approved 2014 capital expenditures of $280,601,000.

The reconciliation of total approved projects to the test year capital expenditures for 2014 along with explanations for significant reconciling items, as provided by Hydro, is as follows:

(000's)	Capital Expenditures
P.U. 42 (2013) (Capital Budget)	$ 97,805.3
P.U. 38 (2013)	1,263.4
P.U. 16 (2014)	109,677.0
P.U. 23 (2014)	580.0
P.U. 29 (2014)	7,197.8
P.U. 32 (2014)	1,452.5
P.U. 33 (2014)	3,632.2
P.U. 34 (2014)	636.7
P.U. 36 (2014)	958.8
P.U. 38 (2014)	259.5
P.U. 45 (2014)	608.9
P.U. 46 (2014)	491.8
P.U. 53 (2014)	2,412.6
O.C. 2014-033	37,484.2
Carryovers per carryover report	15,655.2
Projects under $50K	485.1
Total Approved Projects	**$ 280,601.0**
Reconciling Items	
Items Approved Subsequent to Filing GRA	(1,516.6) [1]
Blackstart Capability Upgrade	(547.9) [2]
Transformer T1 Replacement - Sunnyside	(3,278.4) [3]
100 MW Combustion Turbine Addition	323.0 [4]
Replace Oxen Pond Transformers/TI218 Line Relocation	(7,630.5) [5]
Other Adjustments	75.3
Rounding	(2.9)
Total 2014 GRA forecasted capital expenditures	**$ 268,023.0**

Note 1: This includes P.U. 23 (2014) for $580K, P.U. 38 (2014) for $259.5K, P.U. 46 (2014) for $491.8K and additional projects under $50,000, totalling $185.3K.

Note 2: Due to a reduction in project completion costs between the time of capital project approval and GRA filing.

Note 3: Due to estimated insurance proceeds included in forecasted capital expenditures not included in the Board approved project expenditures.

Note 4: Subsequent to the contents of the GRA being finalized, adjustments were made to the timing of expenditures.

Note 5: Costs related to this project were transferred to the 2015 test year capital budget.

The reconciliation of total approved projects to the forecast capital expenditures for 2015, as provided by Hydro, is as follows:

(000's)		Capital Expenditures	
P.U. 50 (2014) (Capital Budget)	$	76,832.9	
P.U. 16 (2014)		9,248.8	
P.U. 29 (2014)		1,226.4	
P.U. 34 (2014)		360.0	
P.U. 38 (2014)		61.1	
P.U. 45 (2014)		1,238.2	
P.U. 53 (2014)		18,964.7	
O.C. 2014-033		163,145.3	
Total 2015 Approved Projects	**$**	**271,077.4**	
Reconciling Items			
Install Additional Washrooms		259.3	[1]
Purchase a spare Transformer at PRV		160.0	[1]
100 MW Combustion Turbine Addition		(248.8)	[2]
Upgrade Circuit Breakers - Various Sites		2,678.8	[2]
Labrador West Transmission Project		(900.0)	[3]
Replace Oxen Pond Transformers		7,600.0	[4]
Capital Spares		1,540.0	[5]
Replace Unit 1 Air Compressor - Holyrood		(61.1)	
Labrador City Voltage Conversion		(0.4)	
Rounding		0.8	
Total 2015 GRA forecasted capital expenditures	**$**	**282,106.0**	

Note 1: These projects have been cancelled.

Note 2: Subsequent to the contents of the GRA being finalized, adjustments were made to the projected timing of expenditures relating to these projects.

Note 3: Costs related to this project were reduced due to an adjustment to the interest rate on 'Interest During Construction' between the time of capital project approval and GRA filing.

Note 4: Costs relating to this project were transferred from the 2014 capital budget.

Note 5: Estimated critical spares to be procured, as outlined in the report filed with the Board related to Generation Availability on June 16, 2014.

Capital Budget Variance

Table 86: Variances from actual capital expenditures - 2014

(000's)

	Test Year Forecast Additions	Approved at Time of Filing for GRA	Actual Expenditures
	$ 268,026	$ 280,301	$ 204,728
Variance from actual ($)	$ (63,298)	$ (75,573)	
Variance from actual (%)	-30.92%	-36.91%	

We found that actual 2014 capital expenditures were 30.92% less than the test year forecast of $268,026,000 and 36.91% less than the expenditures approved at the time of filing the GRA of $280,301,000.

In CA-NLH-326, the Consumer Advocate asked "…please discuss Hydro's expectation to achieve its forecasted 2014 and 2015 capital expenditures."

Hydro stated the 2014 underspending of $63.3 million was "…primarily attributable to the following:

- The Labrador West Transmission Line was not completed due to a temporary suspension of the work in September. Work is suspended until Alderon completes the financing plan for the Kami mine;
- Work that was planned for completion in 2014 is now being carried into 2015 on a number of projects such as:
  - The new combustion turbine at Holyrood;
  - Load related additions on Isolated Systems;
  - The new transmission line from Bay d'Espoir to Western Avalon; and
  - The Sunnyside transformer project; and
- Expenditures were lower than budgeted primarily related to timing of material delivery. Also, the 2014 variance is largely related to favourable contract pricing, lower than estimated labour and materials, and contingency funds not being utilized on a number of projects."

Hydro indicated in its response to CA-NLH-326 that the forecast expenditures for 2015 of $119.6 million are lower than budgeted expenditures of $282.1 million due to work on the Labrador West Transmission Line being suspended until Alderon completes the financing plan for the Kami mine. Hydro also stated that:

> "With the exception of the forecast underspend for the Labrador West Transmission Line Project, Hydro has planned and expects to achieve its forecasted 2015 capital expenditure, within a variance that is consistent with the level of estimates."

As the Labrador West Transmission Line project is forecast to be included in Work in Progress at December 31, 2015 there is no impact on rate base.

The following table provides a breakdown of the total capital expenditures between those included in rate base and those included in Work in Progress for 2014 actual as compared to the 2014 test year:

Table 87: Breakdown of 2014 Capital Expenditures

(000's)	2014 Test Year	2014 Actual	Difference
Capital Expenditures Included in Rate Base	$ 239,000	$ 91,000	$ 148,000
Work in Progress	29,000	114,000	$ (85,000)
Total Capital Expenditures	**$ 268,000**	**$ 205,000**	**$ 63,000**

Based on our review, the forecast 2014 capital expenditures included in rate base for Test Year 2014 are overstated by approximately $148 million.

We recommend that the Board obtain from Hydro the impact that the above noted variances between forecast and actual expenditures for 2014 and revised forecast expenditures for 2015 have on both the revenue requirement and rate base for the 2014 and 2015 test years.

Deferred Accounts

The following table shows the transactions in the deferred charges account for 2012 and 2013 and those forecast for 2014 and 2015:

Table 88: Deferred charges transactions

(000)'s	Actual Balance Dec 31/12	Actual Balance Dec 31/13	Forecast Add. (Disp)	Forecast Adjustments	Forecast Amort.	Forecast Balance Dec 31/14	Forecast Add. (Disp)	Forecast Amort.	Forecast Balance Dec 31/15
Realized foreign exchange losses	$ 62,551	$ 60,394	$ -	$ -	$ (2,157)	$ 58,237	$ -	$ (2,157)	$ 56,080
Holyrood Blackstart Diesel	-	-	3,684	-	-	3,684	1,554	(1,044)	4,194
Extraordinary Repairs	-	-	-	-	-	-	1,245	(249)	996
Supply Costs Deferral	-	-	9,956	-	-	9,956	-	(1,991)	7,965
General Rate Application	-	-	-	-	-	-	1,000	(333)	667
Conservation Demand Program	2,430	3,878	2,376	-	-	6,254	695	-	6,949
2014 Revenue Deficiency	-	-	45,921	(45,921)	-	-	-	-	-
	$ 64,981	$ 64,272	$ 61,937	$ (45,921)	$ (2,157)	$ 78,131	$ 4,494	$ (5,774)	$ 76,851

Foreign Exchange Losses

Hydro continues to amortize costs associated with foreign exchange losses consistent with past practice.

Holyrood Blackstart Diesel

Hydro deferred lease costs of $3.68 million in the 2014 test year and approximately $1.55 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. The deferral of these costs has been approved under Board Order P.U. 38 (2013) with recovery of these costs to be determined by the Board in a future order. It has been proposed by Hydro that they defer and amortize these amounts over a five-year period starting in 2015. These costs are being reviewed in the prudency review being conducted by the Board ("the Prudency Review").

The proposal will have a forecast revenue requirement impact of approximately $1.0 million in the years 2015-2019.

Extraordinary Repairs

Work required to be completed totalling $1.2 million is forecasted for the 2015 year relating to air blast circuit breakers and transformers to address supply issues and power outages on the Island Interconnected System. Per the May 15, 2014 Board interim report, this repair work was a required action. It has been proposed by Hydro that they defer and amortize these amounts over a five-year period starting in 2015. These costs are being reviewed in the Prudency Review.

The proposal will have a forecast revenue requirement impact of approximately $0.2 million in the years 2015-2019. Similar treatment of a 5 year amortization period occurred in 2006 for work on the Unit 2 boiler tube per Board Order P.U. 44 (2006).

Supply Cost Deferral

Hydro deferred fuel supply costs of approximately $10 million in the 2014 test year associated with additional capacity-related supply costs incurred by Hydro in the first quarter of 2014. The deferral of these costs has been approved under Board Order P.U. 56 (2014). It has also been proposed by Hydro that they defer and amortize these amounts over a five-year period starting in 2015. These costs are being reviewed in the Prudency Review.

The proposal will have a forecast revenue requirement impact of approximately $2 million in the years 2015-2019.

External Regulatory Costs

Approximately $1.0 million in external regulatory costs are forecast to be incurred with respect to the current GRA and it has been proposed by Hydro that they defer and amortize these amounts over a three-year period starting in 2015. This treatment was also included in Newfoundland Power's 2013-2014 GRA and approved under Board Order P.U. 13 (2013).

In relation to the 2013 GRA, Hydro has included $1.0 million of the estimated costs in the 2014 Revenue Deficiency.

The proposal will have a forecast revenue requirement impact of $333,000 in the years 2015, 2016 and $334,000 in 2017.

We conclude that a three year amortization period is consistent with past treatments of regulatory costs approved by the Board.

Conservation Demand Management Costs

Hydro and Newfoundland Power have agreed to a second joint energy conservation plan to increase the level of customer energy savings. In the current GRA, Hydro is proposing regulatory approval for a CDM Cost Deferral Account.

The CDM cost treatment was assessed in the report titled "Cost of Service Study/Utility and Industrial Rate Design Report" prepared by Lummus Consultants in 2013. In that report it was recommended that the CDM costs be deferred and recovered through the use of a rate rider rather than being included in the revenue requirement. The basis for this recommendation is that uneven amounts of CDM costs are incurred from year to year and therefore are more appropriately reflected by the rate rider to match recovery of these amounts.

In the amended GRA Hydro is proposing to revise the recovery mechanism such that for the initial year the Cost Recovery Adjustment will recover 1/7th of the CDM Cost Deferral Account balance at December 31 of the previous year. Then for each subsequent year, the CDM Cost Recovery Adjustment will recover the sum of individual amounts representing 1/7th of the transfer to the CDM Deferral Account for the previous year and amortizations carried forward. This will provide a recovery of the CDM expenses over a discrete seven year period instead of using a rolling balance each year which was proposed in the original GRA. Per the 2014 addendum to the above report, Lummus Consultants have assessed this approach and found it reasonable.

Deferrals for 2009 to 2014 CDM costs were approved in previous Board Orders. Below is a summary of actual versus budget expenditures for 2009 to 2014. Budget amounts represent amounts previously approved for deferral by the Board.

The following table summarizes the actual versus budgeted Conservation Demand Program expenditures from 2009 to 2014:

Table 89: Comparison of Conservation Demand Program expenditures – actual to budget

(000's)	Actual 2014	Actual 2013	Actual 2012	Actual 2011	Actual 2010	Actual 2009	Actual Total
Actual	$ 2,431,000	$ 1,449,000	$1,385,000	$ 474,000	$ 412,000	$ 159,000	**$ 6,310,000**
Budget	2,520,000	1,950,000	1,673,000	840,000	2,300,000	1,800,000	**$ 11,083,000**
Under Budget	$ (89,000)	$ (501,000)	$ (288,000)	$ (366,000)	$(1,888,000)	$(1,641,000)	**$ (4,773,000)**
% Under Budget	(4%)	(26%)	(17%)	(44%)	(82%)	(91%)	(43%)

We conclude that this proposal is consistent with the approach approved for Newfoundland Power under its 2013/2014 GRA, with exception of recovery through the Rate Stabilization Account in Newfoundland Power versus a rate rider as proposed by Hydro, and is reasonably consistent with public utility practice of recovering conservation program costs over a period of 5 – 15 years.

2014 Revenue Deficiency

In 2014 Hydro requested the approval of the deferral and recovery of $45.9 million in forecast revenue deficiency for 2014. They requested the creation of a deferral account and the use of a credit balance in the RSP Hydraulic Variation Account at December 31, 2014 to provide recovery of the $45.9 million. The Board approved the creation of the deferral account in Board Order P.U. 58 (2014), but denied the recovery request.

The following table includes the amortization of the various regulatory deferrals that have been approved in previous Board Orders along with those proposed in this Application and the annual impact on revenue requirement for 2014 to 2019.

Table 90: Analysis of Amortizations Impacts on Revenue Requirement

(000's)	2014	2015	2016	2017	2018	2019
Cost Recovery Deferrals						
Foreign Exchange Losses	$ 2,157	$ 2,157	$ 2,157	$ 2,157	$ 2,157	$ 2,157
Holyrood Blackstart Diesel	-	1,056	1,056	1,056	1,056	1,056
Extraordinary Repairs	-	240	240	240	240	240
Supply Cost	-	1,930	1,930	1,930	1,930	1,930
General Rate Application	-	333	333	334	-	-
Revenue Requirement Impacts	$ 2,157	$ 5,716	$ 5,716	$ 5,717	$ 5,383	$ 5,383

The proposals for amortization in this application all request to start in 2015 and the impact on revenue requirements stay fairly consistent from 2015 to 2019. The only deferral above that will continue amortizing after 2019 is foreign exchange losses. Amortization for this deferral was approved by the Board in 2002 and will continue until 2041.

Amortization for Conservation Demand Program costs are not included in revenue requirement, instead they are recovered through the use of a rate rider.

Proposed Deferral Mechanisms

Isolated Systems Supply Cost Variance Deferral Account

In Hydro's 2013 Amended General Rate Application, Hydro is proposing the use of an Isolated Systems Supply Cost Variance Deferral Account. Hydro has stated that the purpose of this account will be to provide Hydro a reasonable opportunity to recover its supply costs on the Isolated Systems. This deferral account incorporates two accounts that had been proposed in the original GRA – one for cost recovery of diesel and another for purchase power cost variances. The account would be charged or credited by amounts greater than the variance threshold, which Hydro has proposed to be ±$500,000 in a calendar year. A similar threshold is used in Newfoundland Power's "Demand Management Incentive Account", where the demand cost variance must exceed 1% of the test year demand costs before a cost deferral is initiated.

Hydro has indicated that they are seeking approval of a deferral and cost recovery account related to the isolated systems supply costs. Hydro is proposing the account due to upward pressures and on the costs of diesel fuel and certain power purchases and volatility in price of diesel fuel.

The Isolated Diesel Fuel and Purchased Power Costs for the 2007 test year was $12.1 million. During the period 2007 to 2013, the actual cost went from a low of $12.0 million in 2007 to a high in 2013 of $19.7 million. The 2014 and 2015 forecasts are $23.2 million and $21.9 million respectively.

Hydro also noted that it considers this proposed mechanism to be similar to Newfoundland Power's ability to recover energy supply costs variances through its Rate Stabilization Account.

Proposed Definition

In Schedule VI (Section 3: Finance) of the amended Application, Hydro has proposed the following formula for calculating the Isolated Systems Supply Cost Variance:

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

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.

Hydro also noted it will file an application with the Board no later than March 1st of each year for the disposition of any balance in this account.

In NP-NLH-352, Hydro was asked to illustrate the operation of this account for 2012 – 2014, assuming a test year reflecting 2011 actual costs. Their illustration of the hypothetical operation of the account for 2014 is as follows:

Table 91: Illustration of Isolated Systems Supply Cost Deferral Account

Particulars	Diesel	HQ Purchases	Other (Note 1)	Total
A- 2014 Actual Supply Produced and Purchased (kWh)	51,724,605	22,479,190	610,080	74,813,875
B - 2014 Actual Cost / 2014 Actual Production ($/kWh) [B1 / B2]	0.3527	0.1396	0.3091	0.2883
C - 2011 Test Year Cost / 2011 Test Year Production ($/kWh) [C1 / C2]	0.3293	0.1314	0.2752	0.2660
Isolated Supply Costs [A x (B-C)]				1,673,143
Cost Variance Threshold				500,000
Isolated Systems Supply Cost Deferral Balance				**$ 1,173,143**
B1 - 2014 Actual Cost of No. 2 Fuel + Purchases ($)	18,243,816	3,138,097	188,573	21,570,487
B2 - 2014 Actual Production + 2014 Actual Purchases (kWh)	51,724,605	22,479,190	610,080	74,813,875
C1 - 2011 Test Year Cost of No. 2 Fuel + Purchases ($)	15,547,012	2,926,016	108,123	18,581,151
C2 - 2011 Test Year Production + 2011 Test Year Purchases (kWh)	47,206,528	22,265,590	392,880	69,864,998

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

2015 test year data provided by Hydro, which would be used to calculate charges to the account, is as follows:

Table 92: 2015 Test Year Data – Isolated Systems Supply Cost Deferral Account

Particulars	Diesel	HQ Purchases	Other [1]	Total
C - 2015 Test Year Cost / 2015 Test Year Production ($/kWh) [C1 / C2]	0.3215	0.1303	0.2941	0.2665
C1 - 2015 Test Year Cost of No. 2 Fuel + Purchases ($)	18,592,400	3,054,696	173,500	21,820,596
C2 - 2015 Test Year Production + 2015 Test Year Purchases (kWh)	57,838,140	23,435,418	590,000	81,863,558

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

In its response to NP-NLH-381, Hydro said that "the supply cost variance deferral accounts deal with supply cost variances that occur prior to the Labrador-Island interconnection… [which are] not currently recovered through RSP. The requirement for the proposed supply cost deferral accounts beyond the Labrador-Island interconnected will be assessed concurrent with the RSP review planned for 2016."

The proposed deferral account would provide a benefit to ratepayers in the event that actual costs are below the forecast, while protecting Hydro's earnings when the costs are above forecast.

Energy Supply Cost Variance Deferral Account

Hydro is also proposing the implementation of a deferral and recovery mechanism for energy supply cost on the Island Interconnected System. Similar to the proposed Isolated Systems Supply Cost Variance Deferral Account, only variances exceeding the threshold of ±$500,000 would be deferred in this account. The proposed deferral account would be used for both price and quantity variations from the following supply sources on the Island Interconnected System:

- Power purchases from wind generation;

- Power purchases from CBPP cogeneration;
- Power purchases from hydraulic generation;
- Diesel generation; and
- Gas Turbine generation.

In its Application, Hydro explained how energy supply cost variances can arise:

- When the energy requirement is met by a combination of purchased power and Holyrood generation that is different than what was forecast, a variance will exist due to the lower cost to purchase power ($0.04 - $0.15 per kWh) compared to Holyrood production ($0.1537 per kWh);
- In the event of system peaking, area supply requirements, system generation constraints or outages, both quantity and price variances can arise due to the use of diesel and/or gas turbine production at levels that vary from the test year assumption;
- Increases or decreases in the supply of purchased power can lead to variances in the amount of fuel burned at Holyrood from year to year; and
- Each purchase price agreement (PPA), with the exception of Exploits, contains a fixed and a variable component. The variable component increases annually in accordance with increases in the Consumer Price Index. These annual increases in the purchase price of power under the PPAs lead to price variances.

Proposed Definition

In Schedule VII (Section 3: Finance) of the amended Application, Hydro proposes the following formula for calculating the Energy Supply Cost Variance:

$$(A - B) - C$$

Where:

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").

And 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.

Hydro also noted it will file an application with the Board no later than March 1st of each year for the disposition of any balance in this account.

In NP-NLH-351, Hydro was asked to illustrate the operation of this account for 2012 – 2014, assuming a test year reflecting 2011 actual costs. Their illustration of the hypothetical operation of the account for 2014 is as follows

Table 93: Illustration of Energy Supply Cost Variance Deferral Account

Particulars ($)	Wind	CBPP	Hydraulic[1]	Diesel	Gas Turbine	Total
A - 2014 Actual Energy Supply Costs	11,990,074	9,659,724	29,044,806	1,053,654	5,234,409	56,982,667
B - 2011 Test Year Energy Supply Costs	13,102,774	5,916,807	26,859,787	407,232	279,429	46,566,029
C - Energy Supply (Costs)/Savings Based Upon the Cost of Holyrood Generation [D/E x F]						7,258,275
Energy Supply Cost Variance [(A-B)-C]						3,158,363
Cost Variance Threshold						500,000
Energy Supply Cost Variance Deferral Balance						**$ 2,658,363**
D - Holyrood 2011 Test Year Average Fuel Cost (bbl)						91.92
E - 2011 Test Year Fuel Conversion Factor (kWh/bbl)						603
F - Annual kWh variance - 2014 Actual vs. 2011 Test Year (kWh) [F1-F2]						47,614,666
F1 - 2014 Actual Consumption (kWh)						952,316,599
F2 - 2011 Test Year Consumption (kWh)						904,701,933

[1] Includes Nalcor Grand Falls, Bishop Falls and Buchans

Table 94: 2015 Test Year Data – Energy Supply Cost Variance Deferral Account

Particulars ($)	Wind	CBPP	Hydraulic[1]	Diesel	Gas Turbine	Total
B - Test Year Energy Supply Costs	12,732,178	10,281,290	32,280,949	87,140	3,473,690	58,855,247
D - Holyrood 2015 Test Year Average Fuel Cost (bbl)						93.32
E - Test Year Fuel Conversion Factor (kWh/bbl)						607
F2 - Test Year Consumption (kWh)						1,035,230,000

[1] Includes Nalcor Grand Falls, Bishop Falls and Buchans.

In its response to CA-NLH-312, the Consumer Advocate asked why Hydro was not "proposing this type of deferral account for all fuel-related costs on the Island Interconnected System, thus replacing this proposed deferral account and the RSP with a single account…" Hydro indicated that it "does not consider it appropriate to redesign the RSP at this time" due to the full review that is to take place in 2016.

In PUB-NLH-365, the Board requested that Hydro explain why it believes that it should be protected from quantity or price variances in supply from Exploits generation, as such variances may be caused by directives of Government, Hydro's shareholder. Hydro's response indicated that with regards to quantity variances, a positive variance would benefit ratepayers as it would lead to Holyrood fuel savings. Alternatively, a negative variance would mean increased use of Holyrood, against which Hydro's net income is not currently protected. The response also states that the proposal has price variability being "dealt with in the Energy Supply Variance Deferral Account because the costs of diesel fuel, gas turbine fuel and the price for power purchases from wind and CBPP cogeneration change between test years." Hydro indicated that it does not foresee any price variance from Exploits in 2015, and expects to take over ownership of the Exploits generation facilities from Government in 2016.

Holyrood Conversion Factor Deferral Account

In its amended application, Hydro is also proposing the creation of a deferral account for variances associated with the Holyrood Conversion Factor. The proposed account would defer all fuel cost variances that result when the actual conversion factor differs from 607 kWh per barrel (2015 forecast).

When discussing the nature of changes in fuel conversion performance in the Application, Hydro identified the following as causes of the decrease:

- Lower production requirements as a result of reduced systems loads;
- Higher energy purchases; and
- Higher levels of hydraulic generation

These factors contribute overall to lower levels of generation, while under normal circumstances, a thermal unit operates most efficiently at higher levels of generation.

In response to NP-NLH-330, Hydro produced the following table:

	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Forecast
Fuel Consumption ('000 bbls)	1,534.7	1,363.2	1,469.2	1,428.3	1,611.0	2,251.2	2,624.4
Fuel Conversion Rate (kWh/bbl)	612	589	603	599	594	584	607
2007 TY Fuel Conversion Rate (kWh/bbl)	630	630	630	630	630	630	630
Hydro's Financial Loss ($ million)	2.4	4.9	3.5	3.9	5.1	9.0	5.3

This demonstrates that had the proposed deferral account been in place for 2014, approximately $9.0 million would have been deferred (2013 - $5.1 million), based on a 2007 test year. While Hydro is proposing a Fuel Conversion Rate of 607 kWh/bbl for the 2015 test year, this level of efficiency has not been reached since 2009.

Hydro noted in its Application that the improvement in the conversion factor forecasted for 2015 (607 kWh/bbl) over previous year is due to "anticipated higher production requirements and a reduction in minimum operating time which will be enabled by the new CT at Holyrood."

Proposed Definition

In Schedule IX (Section 2: Regulated Activities) Hydro proposes the following formula for calculating the variance that would be deferred:

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

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

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

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

Where: $B = D/E$

D = Actual net Holyrood production (kWh); and

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

Hydro also noted it will file an application with the Board no later than March 1st of each year for the disposition of any balance in this account at December 31st of the previous year.

In NP-NLH-353, Hydro was asked to illustrate the operation of this account for 2012 – 2014, assuming a test year reflecting 2011 actual costs. Their illustration of the hypothetical operation of the account for 2014 is as follows:

Table 95: Illustration of the Holyrood Fuel Conversion Rate Cost Deferral Account

Particulars	2014
A - Actual quantity of No. 6 fuel consumed (bbl)	2,251,225
B - Calculated quantity of No. 6 fuel consumed using the 2011 Test Year Cost of Service fuel conversion rate (bbl)[1]	2,182,745
C - 2011 No. 6 fuel cost ($) per bbl	91.92
Holyrood Fuel Conversion Rate Costs Deferral Balance ($) [(A - B) x C]	**$ 6,294,682**
[1]Calculation of B:	
D - Actual Net Holyrood production (kWh)	1,315,311,289
E - 2011 fuel conversion rate (kWh/bbl)	603

Table 96: 2015 Test Year Data – Holyrood Fuel Conversion Rate Cost Deferral Account

Particulars	2015
C - 2015 Test Year Cost of Service No. 6 fuel cost ($) per bbl	93.32
E - 2015 Test Year Cost of Service fuel conversion rate (kWh/bbl)	607

In NP-NLH-332, Newfoundland Power questioned what incentive would exist for Hydro to optimize the fuel conversion factor if this deferral account is approved. Hydro stated that its "focus will continue to be to provide least cost and reliable power for the ratepayers of the province" and that they will continue efforts to maximize the conversion rate until such time as Holyrood is no longer a prime power producer.

In IC-NLH-179, Hydro was asked why it is not proposing a threshold of ±$500,000 for this account as it has for both the Isolated Systems Supply Cost Variance Deferral Account and the Energy Supply Cost Variance Deferral Account. Hydro responded that this is to "limit its exposure in the recovery of supply costs over which it does not have control." They also noted that the use of a threshold for the other proposed accounts results in a combined limit on Hydro's exposure to ±$1,000,000.

Accounting Matters

Basis of Accounting

On January 20, 2012 we issued our report "Adoption of IFRS for regulatory reporting, effective January 1, 2012" with a supplementary report issued on February 24, 2012. The report was in response to the December 23, 2011 application filed by the Company requesting approval of the adoption by Hydro of International Financial Reporting Standards ("IFRS") for regulatory reporting effective January 1, 2012 ("the IFRS Application").

In the IFRS Application Hydro specifically identified changes in accounting that would be required in order for the Company to adopt IFRS for regulatory purposes (certain of these items had been approved under previous Board Orders). The Company also proposed certain departures from IFRS be permitted, the most significant of these being related to the RSP and deferred charges.

In its response to this application the Board issued P.U. 13 (2012) which approved the adoption of IFRS by Hydro for regulatory purposes effective January 1, 2012 along with certain exceptions.

Subsequent to the issuance of P.U. 13 (2012) significant developments occurred relating to the future of rate regulated accounting.

Historically IFRS was silent on the topic of rate-regulated activities. In 2008, the International Accounting Standards Board ("IASB") undertook a project to decide whether IFRSs should be amended to require the recognition of assets and liabilities arising from rate regulation and provide guidance on their measurement, and/or require disclosures that would assist in the understanding of an entity's regulatory environment. The IASB paused the project in September 2010 and restarted it in September 2012. On September 18, 2012, the Canadian Accounting Standards Board ("AcSB") decided to defer the mandatory IFRS changeover date for entities with qualifying rate-regulated activities to January 1, 2014.

On January 3, 2013, the IASB decided to develop an interim IFRS for use until it completed its comprehensive project for rate regulated accounting. On February 14, 2013, the AcSB extended the existing deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities by an additional year to January 1, 2015.

On April 26, 2013, the IASB issued an Exposure Draft of a proposed interim standard on rate-regulated activities.

The Exposure Draft proposed to:

a. permit an entity that adopts IFRS to continue to use its previous GAAP accounting policies as accepted in their local jurisdiction, for the recognition, measurement and impairment of regulatory deferral account balances;
b. require the entity to present regulatory deferral account balances as separate line items in the statement of financial position and to present movements in those account balances as a separate line item in the statement of profit or loss and other comprehensive income; and
c. require specific disclosures to identify clearly the nature of, and risks associated with, the rate regulation that has resulted in the recognition of regulatory deferral account balances in accordance with the proposals.

The Exposure Draft noted that the standard would only be applicable for an entity's first IFRS financial statements. As a result if Hydro fully adopted IFRS in 2012 they would not be eligible for the relief outlined in the Exposure Draft. Therefore for 2012 the Company continued to use Canadian Generally Accepted Accounting Principles as codified in Part V of the CICA Handbook. However, as P.U. 13 (2012) had been issued, the Company applied the accounting policies that had been approved in this Board Order for regulatory reporting. In its December 31, 2012 audited non-consolidated financial statements Hydro has disclosed its regulatory assets and liabilities as well as regulatory adjustments recorded in the Statement of Income (See Note 5 of the 2012 financial statements). This disclosure outlines regulatory accounting adjustments which differ from Canadian GAAP including those that have been approved in P.U. 13 (2012). Hydro applied the same basis of accounting in 2013 as was used in the 2012 financial statements.

In 2014 the IASB issued IFRS 14 'Regulatory Deferral Accounts' which essentially approved the recommendations of the above noted Exposure Draft. IFRS 14 was applicable for years beginning on or after January 1, 2016 with early adoption permitted.

On April 1, 2015 the Company filed with the Board its annual financial statements for the year ended December 31, 2014. These financial statements were prepared in accordance with IFRS. As permitted the Company elected to early adopt IFRS 14. As such the Company was permitted to continue to recognize regulatory deferral account balances.

The Company has noted it did not change the basis of presentation to IFRS in the amended filing to remain consistent with its original 2013 GRA filing. The Company has noted that "there is no material impact on average rate base or revenue requirement from the application of IFRS and therefore no impact on ratepayers". We asked Hydro if they have completed these calculations based on adoption of IFRS and can the Company provide these calculations. As a response, Hydro referred us to a letter to the Board dated October 23, 2014 for further information on the adoption of IFRS which provided Hydro's continued compliance with P.U.13 (2012) and changes to Hydro's external financial reporting and regulatory reporting.

In the letter dated October 23, 2014 Hydro provided the changes required to regulatory reporting as a result of adoption of IFRS 14 as follows:

- *Capital Assets – Deemed Cost:* Asset costs would be restated to net book value as at January 1, 2013. This is a change in presentation only and will have no impact on ratepayers.

- *Capital Assets – Contributions in Aid of Construction (CIAC):* Under IFRS, Contributions in Aid of Construction are recorded as deferred liabilities and amortized to income over the life of the asset, which differs under Canadian GAAP where CIAC are recorded as a reduction in capital asset costs, with the net amount amortized to depreciation. This is a change in presentation only and will have no impact on ratepayers.

- *Employee Future Benefits:* Under IFRS, actuarial gains and losses on the fair value of the pension plan must be charged to other comprehensive income, which results in an increase in employee future benefit liability, and a corresponding decrease in accumulated other comprehensive income. This is a change in presentation only and will have no impact on ratepayers.

- *Asset Retirement Obligation (AROs)*: Under IFRS the full amount of the obligation is revalued, whereas under Canadian GAAP the obligation is revalued whenever there is an upward increase in the obligation. Using the second quarter of 2014 as an illustration, Hydro stated that this resulted in an increase in the obligation of $0.1 million from $24.5 million to $24.6 million under IFRS at the end of the quarter. The corresponding increase of $0.1 million is an adjustment to property, plant and equipment. According to Hydro, while this change will result in an impact to ratepayers, it is not anticipated to be significant. We also note that the increase for the second quarter of 2014 illustrated by Hydro would result in a higher rate base under IFRS as compared to Canadian GAAP (and the amended filing).

The explanation provided by Hydro in the letter dated October 23, 2014 represents 2014 actual. We did not receive any response on the impact relating to the 2014 test year and 2015 test year.

Asset Retirement Obligations

In its Application, Hydro is proposing to include costs related to the amortization and accretion of Asset Retirement Obligations ("ARO's") in its revenue requirement. The ARO's represent legal or constructive obligations associated with the retirement of long-lived assets. The estimated present value of an ARO is added to the original cost of the related asset ("Asset Retirement Cost" or "ARC"), and an offsetting liability is recognized. Over time, the ARC is depreciated and the ARO accretes toward its future value.

On July 16, 2012 we issued a report in relation to an application filed by Hydro related to Asset Retirement Obligations. Hydro had proposed to exclude the unamortized ARC from rate base and to include depreciation and accretion expense in revenue requirement. In our report we concluded "that the proposed regulatory treatment of the ARO represents a reasonable approach which will allow the Company to recover all costs associated with the ARO over time".

In P.U. 29 (2012) the Board ordered Hydro to recognize and record ARO's in accordance with IFRS but also noted that "the regulatory treatment of the proposed asset retirement obligation is denied at this time". In its decision the Board noted that "the issues surrounding the proposed asset retirement obligations are appropriately addressed in the context of a general rate application so that the assessment can be made and the impacts considered in the context of the relevant circumstances …".

The Company has described its ARO's in Section 3.9.3 of its Application. In addition, the Company has provided calculations to support the ARC, ARO, depreciation expense and accretion expense in its response to NP-NLH-091 (Revision 1, Dec 4-14).

The following table illustrates the continuity of the Asset Retirement Costs and Asset Retirement Obligations from 2010 to the 2015 Test Year:

Table 97: Continuity of asset retirement costs and obligations

Asset Retirement Obligations ($000's)	2010	2011	2012	2013	2014F	2015F
Asset Retirement Costs						
Opening		11,395	17,976	19,684	16,715	14,442
Holyrood ARO	11,395	5,567	3,825	(203)		
PCB ARO		2,163	(73)	(492)		
Holyrood Depreciation		(1,149)	(1,980)	(2,212)	(2,213)	(2,213)
PCB Depreciation			(64)	(62)	(60)	(60)
Closing	11,395	17,976	19,684	16,715	14,442	12,169
Asset Retirement Obligation						
Opening		11,395	19,593	24,032	24,096	24,793
Holyrood ARO	11,395	5,567	3,826	(204)		
PCB ARO		2,163	(73)	(492)		
Holyrood Accretion		468	648	860	804	834
PCB Accretion			68	51	48	44
Dispositions			(30)	(151)	(155)	(144)
Closing	11,395	19,593	24,032	24,096	24,793	25,527

The estimated undiscounted cash flows related to the Holyrood Thermal Generating Station have been agreed to the estimate included in the "Holyrood Thermal Generating Station Decommissioning Study" report issued by Stantec and included in NP-NLH-091 Attachment 2. The estimated undiscounted cash flows related to the PCP removal are based on internal estimates prepared by the Company.

In relation to this evidence we note the following:

- We have reviewed the calculations provided by the Company and recalculated the ARO and the ARC and have not found any discrepancies;

- Depreciation expense of $2.3 million and accretion costs of $0.9 million have been agreed to supporting schedules provided by the Company;

- The Company has calculated the ARO based on the guidance prescribed in CPA (formally CICA) 3110 rather than the IFRS standards (IAS 37 and IFRIC 1). One of the key differences between CPA 3110 and IFRS relates to the calculation of upward adjustments in the estimate of the obligation. Under CPA 3110 only the portion of the liability associated with the upward adjustment is discounted using the current discount rate, whereas under IFRS the whole obligation would be revalued annually using the current discount rate. The CPA guidance results in a more conservative impact on revenue requirement than the IFRS guidance;
- The report prepared by Stantec as provided by the Company in its response to NP-NLH-091 notes that the salvage value of the decommissioned materials has not been calculated. Under both Canadian GAAP and IFRS it is appropriate to exclude salvage value from the calculation of the ARO. However, the salvage value should be used in the calculation of the depreciation of the underlying assets (i.e.: salvage value would reduce depreciation). The Company has noted that it is anticipated that they would not receive any return for scrap materials. The Company also noted that this will be further refined as the project planning proceeds and Hydro moves closer to the actual demolition stage;

- The discount rate used in the calculation of ARO's can have an impact on the value of the reported ARC and the ARO along with the corresponding impact on revenue requirement. When the ARO associated with Holyrood was originally calculated in 2010 the discount rate used was 4.10%. This decreased to 2.90% in 2011 and to 2.78% in 2012. As previously noted the 2.90% and the 2.78% were applied to only the incremental adjustments to the ARO ($6.5 million in 2011 and $5.1 million in 2012 on an undiscounted basis). We recalculated the resulting depreciation expense and accretion costs assuming the discount rate remained at 4.10%. The resulting impact would have been a $19,000 decrease in revenue requirement;

- Estimates related to ARO's are inherently subject to uncertainty regarding the timing and amount of future cash outflows. When the Company initially recorded the ARO related to Holyrood in 2010 the expected undiscounted future cash outflows were $20.5 million. This has now increased to $32.1 million based on the most recent estimates prepared by Stantec. This estimate includes a 10% contingency ($2.9 million). In addition, Stantec has noted that the estimated costs would have an accuracy range of -10% to +30%;

- Including depreciation expense and accretion costs in revenue requirement will permit the Company to recover costs associated with decommissioning the related assets; and

- The Company has excluded the undepreciated ARC from rate base as there are no external costs (either debt or equity) associated with this asset.

Employee Future Benefits

The Company's proposal related to employee future benefits is outlined in Section 3.9.2 of the Application. In this section, the Company is proposing to include the amortization of cumulative actuarial gains and losses as part of the revenue requirement. The impact on 2015 revenue requirement is $1.6 million. This would be consistent with the accounting treatment followed prior to the implementation of P.U. 13 (2012).

As previously noted, P.U. 13 (2012) approved the transition to IFRS effective January 1, 2012, with certain exceptions. The most significant difference between IFRS and Canadian GAAP for employee future benefits relates to the treatment of actuarial gains and losses. As Hydro has identified, under Canadian GAAP actuarial gains and losses above a certain threshold were amortized over the expected average remaining service life of the employee group and as a result, included in revenue requirement. Under IFRS these gains and losses are recognized in Other Comprehensive Income and are not be included in revenue requirement.

The Company has noted that by following P.U. 13 (2012) a portion of the expense associated with employee future benefits would not be included in revenue requirement. We concur that for 2013 under the accounting approved in P.U. 13 (2012) the components of expense related to employee future benefits consists of current service cost and interest and excludes any portion related to the amortization of actuarial gains and losses. We do note that this was identified by the Company in its IFRS Application which preceded the issuance of P.U. 13 (2012). At this time the Company did not propose any regulatory treatment, and no regulatory treatment was ordered to account for actuarial gains and losses.

Permitting the recognition of the amortization of actuarial gains and losses will create a long term difference between regulatory accounting and external financial reporting standards when the Company transitions to IFRS. However, it will permit the recovery of these costs on a timely basis.

Rural Deficit Allocation

Background

As noted in the Rural Deficit Annual Report filed with the Board April 1, 2015, Newfoundland and Labrador Hydro serves approximately 38,000 Rural Customers through its distribution operations. Electrical service is provided to the majority of these customers at an operating loss or deficit, except for the approximately 10,900 Rural Customers served on the Labrador Interconnected System who pay rates which both recover costs, as well as, contribute to funding a portion of the overall rural deficit.

While there is no cost of service prepared by each diesel area or community, generally speaking, revenues from Rural Customers, particularly diesel areas, do not fully recover their fixed costs. Therefore, the incremental cost of fuel is a direct impact to the rural deficit as it is not fully recovered from revenues from increased sales. The following table shows the rural deficit for the years 2010-2014, excluding the Labrador Interconnected System.

Table 98: Rural Deficit Excluding the Labrador Interconnected System (2010 – 2014)

	Annual Amounts ($000,000's)					2014 vs. 2010	
	2010	2011	2012	2013	(Note 1) 2014	$	%
Revenues	$ 53.3	$ 58.4	$ 60.8	$ 62.5	$ 62.6	$ 9.3	17.4%
Costs:							
Operating Expenses	36.2	40.0	43.0	44.4	47.4	$ 11.2	30.9%
Fuel	19.7	26.1	27.6	28.9	35.7	$ 16.0	81.2%
Purchased Power	5.5	7.0	7.5	7.7	7.9	$ 2.4	43.6%
Depreciation	14.2	14.2	11.6	12.5	12.7	$ (1.5)	-10.6%
Return	17.9	20.5	20.4	19.7	23.0	$ 5.1	28.5%
Total	93.5	107.8	110.1	113.2	126.7	$ 33.2	35.5%
Rural Deficit	**$ (40.2)**	**$ (49.4)**	**$ (49.3)**	**$ (50.7)**	**$ (64.1)**	**$ (23.9)**	**59.5%**

Note 1: Because 2014 is a Test Year currently under review by the Board, the 2014 Rural Deficit is estimated based upon the 2014 actual costs combined with a portion of the deferred 2014 Revenue Deficiency allocated to the Rural Deficit.

As illustrated by the table above, the cost of fuel has increased by $16.0 million (81.2%) since 2010, being the largest contributor to the overall increase in costs of $33.2 million. However, total revenues from these rural areas have only increased by $9.3 million since 2010, thus increasing the amount of the Rural Deficit from $40.2 million in 2010 to $64.1 million in 2014.

Existing vs. Proposed Methodology

In its amended application, Hydro is proposing a revised approach for the allocation of the Rural Deficit, where allocation would occur by system based upon revenue requirement, commencing January 1, 2014. This proposal is being made to address the fairness concerns with the current methodology.

The current methodology 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." This methodology was accepted by the Board and was recommended to Hydro as the approach for allocating the Rural Deficit.

As noted in Hydro's response to CA-NLH-166 (Revision 3, March 24-15), Labrador Interconnected rates were changed to reflect the inclusion of the rural deficit in September 2002. Approximately $5.0 million was allocated to the Labrador Interconnected System. However, the impact of the initial allocation of the rural deficit was largely offset by the assignment of a revenue credit of $3.7 million from secondary energy sales to CFB Goose Bay, known as the, "Secondary Revenue Credit". Furthermore, in P.U. 7 (2002-2003), the Board ruled that the Secondary Revenue Credit be applied to reduce the rural deficit rather than applied as a credit against the cost of serving Labrador Interconnected System.

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.

The following table illustrates the impact on each class of customer for the allocation of the Rural Deficit under the existing methodology and the proposed methodology for 2015:

Table 99: 2015 Allocation of the Rural Deficit – Existing Versus Proposed Methodology

Class of Customer	**Existing** (Note 1)		**Proposed** (Note 2)	
	Rural Deficit	**% Allocation**	**Rural Deficit**	**% Allocation**
Newfoundland Power	$ 56,877,694	88.17%	$ 61,662,195	96.24%
Labrador Interconnected	7,628,070	11.83%	2,408,108	3.76%
	$ 64,505,764	100.00%	$ 64,070,303	100.00%

Note 1: As per Schedule 1.2 (Page 1 of 6) of the 2015 Cost of Service updated in accordance with NP-NLH-321.

Note 2: As per Schedule 1.2 (Page 1 of 6) of the 2015 Cost of Service filed by Newfoundland Hydro.

Hydro was asked to comment on the reason why the Rural Deficit balance was different under the existing method compared to the proposed method. In response, Hydro noted that the Rural Deficit as presented under the proposed methodology results in a higher allocation of the rural deficit to Newfoundland Power, which would trigger a higher rate for those customers who follow Newfoundland Power rates, or whose rates are influenced by Newfoundland Power rates. These customers are generally those who would be the main drivers of the Rural Deficit, and any rate increase to these customers would effectively result in higher collection of costs and a lower Rural Deficit.

In response to NP-NLH-398, it was noted that the Board in their 1992 COS Methodology Report provided guidance on assessing fairness when it stated, "Fairness cannot be assessed as due to the method used but instead we must assess fairness on the basis of the result, a shared burden among the classes of customers that is fair to all and not discriminatory." It is Hydro's position that the rural deficit should be allocated so that the amount paid per customer per class is relatively comparable, irrespective of whether customers pay higher or lower rates and irrespective of whether the customers have low kWh usage or high kWh usage.

The following table illustrates the impact on average cost per customer for each class of customer under the existing methodology for the allocation of the Rural Deficit and the proposed methodology:

Table 100: Cost per Customer – Existing versus Proposed Methodology

		Existing (Note 1)			**Proposed** (Note 2)		
Class of Customer	**# of Cust.**	**% Allocation**	**Rural Deficit**	**Cost/Cust.**	**% Allocation**	**Rural Deficit**	**Cost/Cust.**
Newfoundland Power	260,771	88.17%	$ 56,493,728	$ 216.64	96.24%	$ 61,662,195	$ 236.46
Labrador Interconnected	11,600	11.83%	7,576,575	$ 653.15	3.76%	2,408,108	$ 207.60
	272,371		$ 64,070,303			$ 64,070,303	

Note 1: Calculated as per PUB-NLH-393, Attachment 1.

Note 2: Proposed Methodology calculated above is based on the Revenue Requirement Method.

Under the proposed methodology, allocating the Rural Deficit based upon revenue requirement will result in an average cost per customer of $207.60 for customers of the Labrador Interconnected System compared to an average cost of $653.15 under the existing methodology, representing a decrease of 68.2%. Newfoundland Power would experience an increase in average cost per customer of 8.4% under the proposed methodology compared to the existing methodology. As noted by Hydro, the significant impact on rates for customers of the Labrador Interconnected System under the existing methodology has created concern with respect to the reasonableness of the Rural Deficit allocation methodology.

As Hydro noted in its response to CA-NLH-166 (Revision 3, March 24-15), domestic customers on the Labrador Interconnected have materially higher average usage than customers of Newfoundland Power 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 combination of materially higher average usage and the higher average unit cost allocation of the rural deficit to the Labrador Interconnected System predominately explained the higher average cost allocation per customer for the Labrador Interconnected Customers for the 2015 Test Year. Hydro further noted that while Labrador Interconnected Customers comprise 4.3% of the total customers contributing to the rural deficit, they are being required to contribute 11.9% of the rural deficit.

In response to their assessment of fairness, Hydro believes that the current methodology does not provide a reasonable sharing of the rural deficit between the Labrador Interconnected Customers and Newfoundland Power customers. As noted in their response to the Consumer Advocate, the current methodology results in materially higher customer billing impacts for Labrador Interconnected Customers primarily because they have higher electricity usage as a result of living in an area of the Province where the climate is materially colder.

The following table provides a comparison of the proposed rate increase for each class of customer under the existing methodology for the allocation of the Rural Deficit and the proposed methodology:

Table 101: Comparison of proposed rate increases for each class of customer under existing and proposed methodology

	Labrador Interconnected		Newfoundland Power	
	Existing Methodology	Proposed Methodology	Existing Methodology	Proposed Methodology
Revenue Under Existing Rates	$ 20,093,239	$ 20,093,239	$ 415,402,365	$ 415,402,365
Revenue Under Proposed Rates *	$ 25,735,419	$ 20,520,143	$ 520,544,648	$ 525,340,174
Percentage Change in Rates	28.1%	2.1%	25.3%	26.5%

*Revenue under proposed rates for Newfoundland Power is prior to the NP fuel rider

The proposed rate increase for Labrador Interconnected Rural customers would increase to 28.1% under the existing methodology for the allocation of the Rural Deficit, compared to a 2.1% increase under the proposed methodology. Prior to the application of the NP fuel rider, the proposed rate increase for Newfoundland Power customers would increase to 25.3% under the existing methodology, compared to 26.5% increase under the proposed methodology.