NP 2019-2020 General Rate Application
Information Item - #1
Filed: 2018-10-03 Board Secretary: CB

Grant Thornton
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Board of Commissioners of Public Utilities
2015 Annual Financial Review of Newfoundland Power Inc.

Contents

Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2015 Annual Financial Review of Newfoundland Power Inc. ("the Company") ("Newfoundland Power"). Below is a summary of the key observations and findings included in our report.

The average rate base for 2015 was $1,019,082,000 compared to average rate base for 2014 of $964,930,000 and 2013 of $915,820,000. The Company's calculation of the return on average rate base for 2015 was 7.48% (2014 - 7.83%) compared to an approved rate of return of 7.50%. The actual rate of return was within the range approved by the Board (7.32% to 7.68%). The calculations of average rate base and rate of return on average rate base are in accordance with established practice and Board orders.

The Company's calculation of average common equity for 2015 was $451,501,000 (2014 - $429,174,000). The Company's actual return on average common equity for the year ended December 31, 2015 was 8.98% (2014 – 9.15%). In P.U. 32 (2007) the Board ordered that where in a given year the actual rate of return on equity (ROE) is greater than 50 bps above the test year calculation of the cost of equity for the same year (or as determined by the Automatic Adjustment Formula outside a test year), the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2015 the cost of common equity was 8.80% as per P.U. 13 (2013). The actual return on average common equity for 2015 was 8.98% as noted above. This return was within the 50 basis point trigger and as such no report was required.

The actual capital expenditures (excluding capital projects carried forward from prior years) were 3.12% over budget in 2015. The capital expenditures exceeded the approved budget (including projects carried over from prior years) on a net basis by $6,467,000 (5.34%). However, for each category of expenditure, the variances ranged from an over-budget of 19.29% to an under-budget of 36.59%. Significant variances are explained in our report.

The Company experienced a 3.25% increase in revenue from rates in 2015 as compared to 2014. The increase can be explained by an increase in customer energy rates effective July 1, 2015 combined with higher electricity sales.

Net operating expenses in 2015 increased by $74,000 from 2014. There was a substantial increase in Pension and early retirement expenses but these costs were offset by decreases in Labour and OPEB's costs. These and other significant operating expense variances are discussed in our report. We conducted an examination of other costs including purchased power, depreciation, interest and income taxes and have noted that nothing has come to our attention to indicate that these costs for 2015 are unreasonable.

Non-regulated expenses, net of tax, decreased in 2015 by $189,400. This variance is primarily due to the fact that there was executive stock option expenses of $321,602 in 2014 but there was only $147,009 stock option expenses in 2015.

Our analysis of the Company's regulatory assets and liabilities indicated that all were in accordance with applicable Board Orders.

Based on our review, the 2015 Pension Expense Variance Deferral Account (PEVDA) operated in accordance with P.U. 43 (2009).

Based on our review, the 2015 Other Post-Employment Benefits Cost Variance Deferral Account (OPEBVDA) operated in accordance with P.U. 31 (2010).

Based on our review, the 2015 Optional Seasonal Rate Revenue and Cost Recovery Account operated in accordance with P.U. 8 (2011) and P.U. 13 (2013).

The Company continues to undertake initiatives aimed at improving reliability of service and efficiency of operations as is summarized in the Section entitled 'Productivity and Operating Improvements'. During 2015 the Company met six out of nine of its planned performance measures. The Company fell short of its targets in the following categories: "Outage/Customer (SAIFI) – excluding Hydro loss of supply", "Plant Availability", "% of Satisfied Customers as measured by Customer Satisfaction Survey."

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2015 Annual Financial Review of Newfoundland Power Inc. ("the Company") ("Newfoundland Power").

Scope and Limitations

Our analysis was carried out in accordance with the following Terms of Reference:

1. Examine the Company's system of accounts to ensure that it can provide information sufficient to meet the reporting requirements of the Board.

2. Review the Company's calculations of return on rate base, return on equity, embedded cost of debt, capital structure and interest coverage to ensure that they are in compliance with Board Orders.

3. Conduct an examination of operating and administrative expenses, purchased power, depreciation, interest and income taxes to review them in relation to sales of power and energy and their compliance with Board Orders.

   Our examination of the foregoing will include, but is not limited to, the following expense categories:

   - advertising,
   - bad debts (uncollectible bills),
   - company pension plan,
   - costs associated with curtailable rates,
   - demand side management,
   - donations,
   - general expenses capitalized (GEC),
   - income taxes,
   - interest and finance charges,
   - membership fees,
   - miscellaneous,
   - non-regulated expenses,
   - purchased power,
   - salaries and benefits,
   - travel, and
   - amortization of regulatory costs.

4. Review intercompany charges and assess compliance with Board Orders including requirements for additional reports pursuant to P.U. 19 (2003) and P.U. 32 (2007).

5. Examine the Company's 2015 capital expenditures in comparison to budgets and prior years and follow up on any significant variances. Included in this review will be an analysis of amounts included in 'Allowance for Unforeseen Items'.

6. Review the Company's rates of depreciation and assess their compliance with the Gannett Fleming Depreciation Study included in the 2013-14 GRA, and review the calculations of depreciation expense.

7. Review Minutes of Board of Directors' meetings.

8. Review the Company's initiatives and efforts with respect to productivity improvements, rationalization of operations and expenditure reductions. Inquire as to the Company's reporting on Key Performance Indicators.

9. Conduct an examination of the changes to deferred charges and regulatory deferrals.

10. Conduct an examination of the Pension Expense Variance Deferral Account to assess compliance with P.U. 43 (2009).

11. Conduct an examination of the OPEBs Cost Variance Deferral Account and the amortization of the Company's transitional balance to assess compliance with P.U. 31 (2010).

12. Conduct an examination of the Optional Seasonal Rate Revenue and Cost Recovery Account compliance with P.U. 8 (2011) and P.U. 13 (2013).

13. Conduct an examination of the deferred cost recovery relating to the 2012 Cost of Capital in compliance with P.U. 17 (2012) and its amortization in compliance with P.U. 13 (2013).

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

- inquiry and analytical procedures with respect to financial information as provided by the Company; and
- examination of, on a test basis where appropriate, documentation supporting amounts included in the Company's records.

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

The financial statements of the Company for the year ended December 31, 2015 have been audited by Ernst and Young LLP, Chartered Professional Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 2, 2016. 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.

System of Accounts

Section 58 of the *Public Utilities Act* permits the Board to prescribe the form of accounts to be maintained by the Company.

The objective of our review of the Company's accounting system and code of accounts was to ensure that it can provide information sufficient to meet the reporting requirements of the Board. We have observed that the Company has in place a well-structured, comprehensive system of accounts and organization/reporting structure. The system allows for adequate flexibility to allow the Company to meet its own and the Board's reporting requirements.

On March 28, 2014, the Company filed a revised system of accounts as part of its 2013 Annual Report. In submitting these changes the Company noted that the revisions were mainly due to accounts approved by the Board over the last two years.

According to the Company there have been no further significant changes to the system of accounts since this time.

Based upon our review of the Company's financial records we have found that they are in compliance with the system of accounts prescribed by the Board. The system of accounts is comprehensive and well-structured and provides adequate flexibility for reporting purposes.

Return on Rate Base and Equity, Capital Structure and Interest Coverage

Scope: ***Review the Company's calculations of return on rate base, return on equity, capital structure and interest coverage to ensure that they are in compliance with Board Orders.***

Calculation of Average Rate Base

The Company's calculation of its average rate base for the year ended December 31, 2015 which is included on Return 3 of the annual report to the Board was computed using the Asset Rate Base Method ("ARBM"). The average rate base for 2015 was $1,019,082,000 which is an increase of $54,152,000 (5.61%) over the average rate base for 2014 of $964,930,000. The increase was primarily a result of an increase in plant investment.

Our procedures with respect to verifying the calculation of the average rate base were directed towards the verification 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 audited financial statements and internal accounting records, where applicable;
- agreed component data (capital expenditures; depreciation; etc.) to supporting documentation;
- checked the clerical accuracy of the continuity of the rate base for 2015; and
- agreed the methodology used in the calculation of the average rate base to the Public Utilities Act to ensure it is in accordance with Board Orders and established policy and procedure.

The following table summarizes the components of the average rate base for 2015, 2014 and 2013 (all figures shown are averages):

(000)'s	2015	2014	2013
Net Plant Investment (average)			
Plant Investment	**$1,629,189**	$1,547,173	$ 1,470,688
Accumulated Depreciation	**(657,233)**	(634,736)	(613,131)
CIAC's	**(33,970)**	(32,806)	(31,459)
	937,986	879,631	826,098
Additions to Rate Base (average)			
Deferred Charges (a)	**101,448**	102,584	100,756
Cost Recovery Deferral for Seasonal/TOD Rates (b)	**59**	82	94
Cost Recovery Deferral for Hearing Costs (c)	**161**	483	322
Cost Recovery Deferral for Regulatory Amortizations (d)	**553**	1,661	2,767
Cost Recovery Deferral – 2012 Cost of Capital (e)	**294**	883	1,472
Cost Recovery Deferral – 2013 Revenue Shortfall (f)	**563**	1,689	1,126
Cost Recovery Deferral – Conservation (g)	**6,200**	3,511	1,156
Customer Finance Programs (h)	**1,174**	1,250	1,405
	110,452	112,143	109,098
Deductions from Rate Base (average)			
Weather Normalization Reserve (i)	**(1,386)**	3,349	4,931
Other Post-Employment Benefits (j)	**35,822**	27,975	19,066
Customer Security Deposits (k)	**973**	750	846
Accrued Pension Obligation (l)	**4,795**	4,480	4,173
Deferred Income Taxes (m)	**1,899**	2,201	2,188
Excess Earnings (n)	**49**	25	-
Demand Management Incentive Account (o)	**223**	87	143
	42,375	38,867	31,347
Average Rate Base before Allowances	**1,006,063**	952,907	903,849
Rate Base Allowances			
Materials and Supplies	**6,280**	5,619	5,445
Cash Working Capital	**6,739**	6,404	6,526
	13,019	12,023	11,971
Average Rate Base	**$ 1,019,082**	$ 964,930	$ 915,820

(a) The Company's rate base is determined using the Asset Rate Base Method which incorporates average deferred charges into the calculation of rate base. The total average deferred charges of $101,448,000 (2014 - $102,584,000) included in the 2015 rate base consists of average deferred pension costs of $101,384,000 (2014 - $102,548,000) and credit facility costs of $64,000 (2014 - $36,000). The Company has included a schedule of these costs in Return 8.

(b) In P.U. 8 (2011) the Board approved the Optional Seasonal Rate Revenue and Cost Recovery Account. Pursuant to P.U. 8 (2011), "on December 31st of each year from 2011 until further order of the Board, this account shall be charged with: (i) the current year revenue impact of making the Domestic Seasonal – Optional Rate available to customers and (ii) the operating costs associated with implementing the Domestic Seasonal – Optional and the Time-of-Day Rate Study". The calculation of the 2015 average rate base incorporates $59,000 (2014 - $82,000) related to this deferral account.

(c) In P.U. 13 (2013) the Board approved the creation of a Hearing Cost Deferral Account to recover over three years, commencing January 1, 2013, hearing costs related to the 2013/2014 GRA in the amount of $1,250,000. During 2013, the Company deferred $965,000, $285,000 lower than the approved amount, of 2013/2014 GRA hearing costs. Amortization of approximately $322,000 was recorded in each of the three years; 2013, 2014 and 2015, relating to these costs. The 2015 average rate base includes an addition of $161,000 (2014 - $483,000) which represents the unamortized average balance of the original $965,000. These costs have been fully amortized as of December 31, 2015.

(d) On August 31, 2010 Newfoundland Power submitted an application proposing to defer recovery, until a further Order of the Board, of the amount of $2,363,000 ($1,642,000 after tax) in 2011 to offset the net impact of the expiring amortizations relating to the Municipal Tax Liability, Unrecognized 2005 Unbilled Revenue, Deferred Energy Replacement Costs and the Purchased Power Unit Cost Variance Reserve. This application was approved by the Board in P.U. 30 (2010). P.U. 22 (2011) approved the deferral in 2012 of an additional $2,363,000 ($1,678,000 after tax) related to these expiring amortizations. In P.U. 13 (2013) the Board approved three year amortization of these deferrals commencing January 1, 2013. Amortization of approximately $1,107,000 was recorded in each of the three years; 2013, 2014 and 2015, relating to these costs. The 2015 average rate base includes an addition of $553,000 (2014 - $1,661,000) which represents the unamortized average balance of the original $3,320,000. These costs have been fully amortized as of December 31, 2015.

(e) In P.U. 17 (2012) the Board approved the deferred recovery of the full amount of the difference in revenue between an 8.38% return on common equity and an 8.80% return on common equity for 2012, calculated on the basis of Newfoundland Power's 2010 test year costs. In P.U. 13 (2013) the Board approved three year amortization of these deferrals commencing January 1, 2013. Amortization of approximately $588,000 was recorded in each of the three years; 2013, 2014 and 2015, relating to these costs. The 2015 average rate base includes an addition of $294,000 (2014 - $883,000) which represents the unamortized average balance of the original deferral. These costs have been fully amortized as of December 31, 2015.

(f) In P.U. 13 (2013) the Board approved the deferral and amortization over three years of amounts related to Newfoundland Power's shortfall in the recovery of revenue requirements for 2013. As a result of this order and updated revenue forecasts subsequently filed by Newfoundland Power in an *Application Filed in Compliance with Order No. P.U. (2013)*, an amount of $3,965,000 ($2,815,000 after tax) has been deferred. Based on a rate implementation date of July 1, 2013, the amortization period had subsequently been updated to 30 months, resulting in amortization for 2013 of $563,000 and amortization of $1,126,000 for 2014 and 2015. The 2015 average rate base includes an addition of

$563,000 (2014 - $1,689,000) which represents the unamortized average balance of the original 2,815,000. These costs have been fully amortized as of December 31, 2015.

(g) In P.U. 43 (2009) the Board approved Newfoundland Power's proposal to recover the 2009 conservation programming costs of approximately $1,500,000 ($1,020,000 after tax) over the remaining four years of the 5-year Energy Conservation Plan. These costs were fully amortized in 2013. In P.U. 13 (2013) the board approved Newfoundland Power's proposed change in definition of conservation program costs and the deferral and amortization of annual conservation program costs over seven years with recovery through the Rate Stabilization Account. The actual costs incurred and deferred in 2013 were $2,937,000 ($2,085,000 after tax) resulting in annual amortization of $298,000 in 2014. The actual costs incurred and deferred in 2014 were $4,436,000 ($3,150,000 after tax) resulting in additional annual amortization of $450,000 to commence in 2015. The actual costs incurred and deferred in 2015 were $4,611,000 ($3,274,000 after tax) resulting in additional annual amortization of $468,000 to commence in 2016. Included in the calculation of the average rate base for 2015 is $6,200,000 (2014 - $3,511,000) related to this deferral.

(h) Customer Finance Programs are comprised of loans provided to customers related to customer conservation programs and contributions in aid of construction. The 2015 average rate base incorporates $1,174,000 (2014 - $1,250,000) related to these programs.

(i) During 2015, the Weather Normalization reserve was impacted by the following:

Transfer to RSA

i. In P.U. 13 (2013) the Board approved annual balances in the Weather Normalization reserve be recovered from or credited to customers through the Rate Stabilization Account. This resulted in a transfer increase to the reserve of $33,000 in 2015 (2014 – $1,712,000 decrease).

Other transfers:

i. $108,000 transfer decrease (2014 – $104,000 decrease) to the reserve related to the after tax impact of the Degree Day Normalization Reserve Transfer.
ii. $4,303,000 transfer decrease (2014 - $71,000 increase) to the reserve related to the after tax impact of the Hydro Production Equalization Reserve transfer.

Amortization

i. Also in P.U. 13 (2013) the Board approved a three year amortization of the 2011 balance in the Weather Normalization Reserve of $5,020,000 resulting in a decrease to the reserve of $1,673,000 of amortization for 2015 (2014 - $1,673,000 decrease).

The net impact was a net decrease to the reserve of $6,051,000 (2014 - $3,418,000 decrease). The ending balance in this reserve account totaled ($4,411,000) compared to a balance of $1,640,000 at December 31, 2014 (an average of ($1,386,000) for 2015 (2014 - $3,349,000)).

(j) Other Post-Employment Benefits is equal to the difference, at December 31, 2015, between the OPEBs liability of $74,248,000 and the OPEBs asset of $35,040,000. The calculation of the 2015 average rate base of $35,822,000 is equal to the average of the December 31, 2015 net liability of $39,208,000 and the December 31, 2014 net liability of $32,435,000.

(k) Customer Security Deposits are comprised of security deposits received from customers for electrical services in accordance with the Board-approved Schedule of Rates, Rules and Regulations. The calculation of the 2015 average rate base incorporates $973,000 (2014 - $750,000) related to customer security deposits.

(l) The 2015 average rate base calculation incorporates $4,795,000 (2014 - $4,480,000) of Accrued Pension Obligation. This obligation is a result of executive and senior management supplemental pension benefits comprised of a defined benefit plan and a defined contribution plan. The defined benefit plan was closed to new entrants in 1999.

(m) In P.U. 32 (2007) the Board approved the Company's adoption of the accrual method of accounting for income tax related to pension costs. In P.U. 31 (2010) the Board approved the Company's adoption of the accrual method of accounting for other post-employment benefits (OPEBs) costs and income tax related to OPEBs. The balance of deferred income taxes related to pension costs and OPEBs included in the 2015 average rate base is $656,000 and ($9,695,000) respectively. The remaining balance of the deferred income tax liability in the amount of $10,938,000 relates to capital assets. This results in an average balance for deferred income tax liability of $1,899,000 (2014 - $2,201,000).

(n) In P.U. 23 (2013) the Board approved the definition of the Excess Earnings Account. In 2013, Newfoundland Power's regulated earnings exceeded the upper limit of allowed regulated earnings by $49,000 after tax. The average rate base originally filed in the 2013 Return 3 and Return 13 used an understated average rate base balance of $915,612,000. The understated average rate base produced an excess earnings liability of $68,000 ($49,000 after tax). An average rate base of $915,820,000 was subsequently filed by the Company in Schedule D of its 2015 Capital Budget Application. This revised rate base produces excess earnings of $46,000 ($33,000 after tax). The Company has noted as the original calculation is not materially higher than the revised calculation, it has not adjusted the excess earnings account. This represents a benefit to the customer.

(o) In P.U. 7 (2014) the Board approved the disposition of the 2013 balance of the Demand Incentive Account of $383,085 (($271,990) after tax) by means of a debit to the Rate Stabilization Account as of March 31, 2014. In P.U. 8 (2015) the Board approved the disposition of the 2014 balance of the Demand Incentive Account of $627,503 ($445,527 after tax) by means of a credit to the Rate Stabilization Account as of March 31, 2015. The 2015 balance of the Demand Incentive Account was $Nil as there was no supply cost variance outside the Deadband. The 2015 average rate base incorporates $223,000 (2014 - $87,000) related to this account.

The net change in the Company's average rate base from 2014 to 2015 can be summarized as follows:

(000's)	**2015**	2014
Average rate base - opening balance	**$ 964,930**	$ 915,820
Change in average deferred charges and deferred regulatory costs	**(1,615)**	3,200
Average change in:		
Plant in service	**82,016**	76,485
Accumulated depreciation	**(22,497)**	(21,605)
Contributions in aid of construction	**(1,164)**	(1,347)
Weather normalization reserve	**4,735**	1,582
Other post employment benefits	**(7,847)**	(8,909)
Future income taxes	**302**	(13)
Rate base allowances	**996**	52
Other rate base components (net)	**(774)**	(335)
Average rate base - ending balance	**$ 1,019,082**	$ 964,930

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2015 average rate base, and therefore conclude that the 2015 average rate base included in the Company's annual report to the Board is accurate and in accordance with established practice and Board Orders.

Return on Average Rate Base

The Company's calculation of the return on average rate base is included on Return 13 of the annual report to the Board. The return on average rate base for 2015 was 7.48% (2014 – 7.83%). Our procedures with respect to verifying the reported return on average rate base included agreeing the data in the calculation to supporting documentation and recalculating the rate of return to ensure it is in accordance with established practice and Board Orders. For 2015, the return on average rate base is calculated in accordance with the methodology approved in P.U. 13 (2013).

The actual return on average rate base in comparison to the range of allowed return for each of the years from 2013 to 2015 is set out in the table below.

	2015	**2014**	**2013**
Actual Return on Average Rate Base	**7.48%**	7.83%	8.10%
Upper End of Range set by the Board	**7.68%**	8.06%	8.10%
Lower End of the Range set by the Board	**7.32%**	7.70%	7.74%

The Board approved the Company's rate of return on average rate base of 7.50% in a range of 7.32% to 7.68% for 2015 in P.U. 51 (2014). As noted above, the Company's actual return on average rate base for 2015 was 7.48% which was inside the range set by the Board.

The actual rate of return for 2014 was within the range set by the Board.

The 2013 rate of return on average rate base was outside the range set by the Board (2013 actual return on average rate base of 8.1036%) therefore the Company recorded a regulatory liability and decrease in earnings in the amount of $68,000 ($49,000 after tax). As a result of the revised average rate base we calculated excess earnings of $42,000 ($33,000 after tax). In discussions with the Company they determined the additional excess earnings of $26,000 ($16,000 after tax) reported in Return 13 were immaterial to file a revised return. This represents a benefit to the customer. See 'Regulatory Assets and Liabilities' section of our report for further details.

As a result of completing these procedures, we can advise that no discrepancies were noted and therefore conclude that the calculation of rate of return on average rate base included in the Company's annual report to the Board is in accordance with established practice.

Capital Structure

In P.U. 13 (2013) the Board reconfirmed its previous position as per P.U. 43 (2009) regarding the capital structure for Newfoundland Power Inc. and the Board has deemed that the proportion of common equity in the capital structure shall not exceed 45%.

The Company's capital structure for 2015 as reported in Return 24 is as follows:

	2015 Average		2014	2013
	(000's)	**Percent**	Percent	Percent
Debt	**$559,350**	**54.85%**	54.85%	54.35%
Preferred equity	**8,944**	**0.88%**	0.92%	0.97%
Common equity	**451,501**	**44.27%**	44.23%	44.68%
	$1,019,795	**100.00%**	100.00%	100.00%

Pursuant to P.U. 32 (2007), the Company did submit a schedule (Return 25) calculating the cost of embedded debt for the current year. It also indicated the variances in interest expense and average debt over the 2014 test year in Return 26. The embedded cost of debt for 2015 was 6.50% which represents a 49 bps decrease from 2014 embedded cost of debt of 6.99%.

Based on the information indicated above, we conclude that the capital structure included in the Company's annual report to the Board is in compliance with Board Order P.U. 13 (2013).

Calculation of Average Common Equity and Return on Average Common Equity

The Company's calculation of average common equity and return on average common equity for the year ended December 31, 2015 is included on Return 27 of the annual report to the Board. The average common equity for 2015 was $451,501,000 (2014 - $429,174,000). The Company's actual return on average common equity for 2015 was 8.98% (2014 – 9.15%).

Similar to the approach used to verify the rate base, our procedures in this area focused on verification 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 audited financial statements and internal accounting records where applicable;
- agreed component data (earnings applicable to common shares; dividends; regulated earnings; etc.) to supporting documentation;
- checked the clerical accuracy of the continuity of book common equity per P.U. 40 (2005), including the deemed capital structure per P.U. 19 (2003), P.U. 32 (2007), P.U. 43(2009) and P.U. 13 (2013).
- recalculated the rate of return on common equity for 2015 and ensured it was in accordance with established practice, P.U. 32 (2007), and P.U. 13 (2013).

In P.U. 32 (2007) the Board ordered that where in a given year the actual rate of return on equity (ROE) is greater than 50 bps above the test year calculation of the cost of equity for the same year (or as determined by the Automatic Adjustment Formula outside a test year), the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2015 the cost of common equity was 8.80% as per P.U. 13 (2013). The actual return on average common equity for 2015 was 8.98% as noted above. This return was within the 50 basis point trigger and as such no report was required.

Based on completion of the above procedures we did not note any discrepancies in the calculations of regulated average common equity or return on regulated average common equity.

Interest Coverage

The level of interest coverage experienced by the Company over the last three years is as follows:

(000's)	2015	2014	2013
Net income	**$ 39,314**	$ 37,840	$ 49,920
Income taxes	**10,925**	10,795	(2,877)
Interest on long term debt	**35,020**	36,327	35,123
Interest during construction	**(1,240)**	(1,435)	(893)
Other interest and amortization of debt discount costs	**1,361**	880	1,377
Total	**$ 85,380**	$ 84,407	$ 82,650
Interest on long term debt	**$35,020**	$36,327	$35,123
Other interest and amortization of debt discount costs	**1,361**	880	1,377
Total	**$36,381**	$37,207	$36,500
Interest Coverage (times)	**2.3**	2.3	2.3

The above table shows that the interest coverage did not change from 2014 to 2015.

In P.U. 43 (2009) the Board was satisfied with the Company's interest coverage ratio of 2.5 times given the Company's capital structure and return on regulated equity. The level of interest coverage realized for 2015 is 2.3 times.

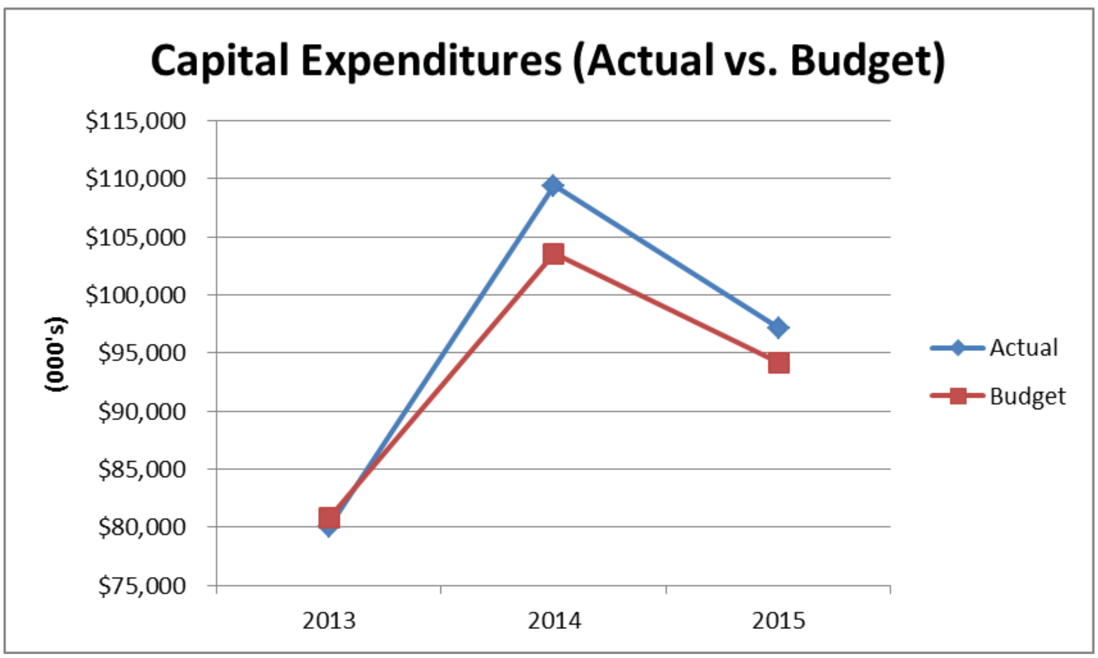
Capital Expenditures

Scope: ***Review the Company's 2015 capital expenditures in comparison to budgets and follow up on any significant variances.***

The following table details the actual versus budgeted capital expenditures (excluding capital projects carried forward from prior years) for the past three years from 2013 to 2015:

($000's)	2013	2014	2015	Notes
Actual	$ 80,013	$ 109,429	$ 97,155	1
Budget	$ 80,788	$ 103,572	$ 94,211	
Over (under) budget	(0.96%)	5.66%	3.12%	

Note 1: Total expenditures per the 2015 Capital Budget report includes the carryover amount of $3,772,000 for a total of $100,927,000. The carryover amount is made up of six projects included in the following categories: $180,000 to generation - hydro; $161,000 to substations; $660,000 to transmission; $503,000 to distribution; $1,018,000 to general property; and $1,250,000 to information systems. According to the Company, these expenditures will occur in 2016.



The following table provides a summary of the capital expenditure activity in 2015 as reported in the Company's *"2015 Capital Expenditure Report"*:

($000's)	Capital Budget			Actual Expenditures		
	Prior Years	2015	Total	Prior Years	2015	Total
2015 Capital Projects (1)	$ -	$ 94,211	$ 94,211	$ -	$ 97,155	$ 97,155
2014 Projects Carried to 2015 & Multi Year Projects						
Hydro Plant Production Increase - 2014	1,665	-	1,665	899	931	1,830
Facility Rehabilitation - 2014 (2)	1,610	-	1,610	1,538	410	1,948
Additions due to Load Growth - 2014	5,250	-	5,250	4,385	375	4,760
Rebuild Transmission Lines - 2014	5,099	-	5,099	4,522	342	4,864
Trunk Feeders - 2014 (3)	1,261	-	1,261	1,544	621	2,165
Feeder Additions for Growth - 2014 (4)	1,102	-	1,102	1,360	250	1,610
Hearts Content Plant Refurbishment - Multi Year	5,935	-	5,935	6,164	206	6,370
Rattling Brook Refurbishment - Multi Year	5,000	-	5,000	2,957	69	3,026
	26,922	-	26,922	23,369	3,204	26,573
Grand Total	**$ 26,922**	**$ 94,211**	**$ 121,133**	**$ 23,369**	**$ 100,359**	**$ 123,728**

(1) Approved by Order P.U. 40 (2014).

(2) The Company has noted that the unfavorable variance to budget primarily relates to the poor bedrock conditions discovered during excavation of The Cape Broyle Spillway project, and the work did not get completed as planned in 2014.

(3) The Company has noted that the unfavorable budget variance primarily was a result of additional costs resulted from a design change to permit voltage conversion on the distribution lines being relocated. Additionally, the budget cost of the 2014 Manhole Cover Replacement project was underestimated, which was provided by a third party.

(4) The Company has noted that the unfavorable budget variance primarily was a result of an increase in actual costs over budget relating to three feeder upgrades and additions.

A breakdown of the total capital expenditures and budget with variances by asset category is as follows:

($000's)	2015 Budget (1)	2015 Actuals (2)	Variance	Carryover (3)	Variance Including Carryover	%
Generation - Hydro	$ 18,908	$ 17,898	$ (1,010)	$ 280	$ (730)	(3.86%)
Generation - Thermal	216	228	12	-	12	5.56%
Substation	27,728	27,042	(686)	161	(525)	(1.89%)
Transmission	10,830	10,595	(235)	660	425	3.92%
Distribution	44,836	51,587	6,751	503	7,254	16.18%
General property	3,224	2,045	(1,179)	1,018	(161)	(4.99%)
Transportation	2,917	3,080	163	-	163	5.59%
Telecommunications	123	78	(45)	-	(45)	(36.59%)
Information systems	7,501	6,284	(1,217)	1,250	33	0.44%
Unforeseen	750	-	(750)	-	(750)	(100.00%)
General expenses capitalized	4,100	4,891	791	-	791	19.29%
Total	**$ 121,133**	**$ 123,728**	**$ 2,595**	**$ 3,872**	**$ 6,467**	**5.34%**

1 - Includes prior years projects and current year budgeted amounts as there were projects incomplete at the previous year ends.
2 - 2015 actuals include the total expense for projects carried forward from the years 2013 to 2014.
3 - Represents $3,772,000 included in the 2015 budget and an amount of $100,000 from a Multi-year budget, but not yet spent.

As indicated in the table, capital expenditures were greater than the approved budget (including projects carried over from prior years) on a net basis by $2,595,000 and by $6,467,000 (5.34%) when carryover amounts are taken into account. However, for each category of expenditure, the variances ranged from an over-budget of 19.29% for the General expenses capitalized category to an under-budget of 36.59% for the Telecommunications category. As the variances within the table are for category totals it should be noted that individual project variances will differ from those listed. A breakdown by project of the carryover amounts from the table above is as follows:

Project	**Carryover (000's)**
Facility Rehabilitation	$ 180
Substation Refurbishment and Modernization	161
Transmission Line Rebuild	660
Trunk Feeders	503
Renovations to Company Buildings	1,018
SCADA System Replacement	1,250
Rattling Brook Fisheries Compensation Project	100
Total Carryover	**$ 3,872**

The Company has provided detailed explanations on budget to actual variances in its "2015 Capital Expenditure Report". For a complete review of the budget variance we refer the reader to this report, Appendix A.

Adherence to Capital Budget Application Guidelines

Based on our review, the Company's 2015 capital expenditures are in accordance with the Capital Budget Application Guidelines Policy #1900.6 Sections A and C as noted below:

- Under Section A, as required, the Company filed its annual capital budget application by July 15th and followed appropriate guidelines for the format of the application submitted.

- Under Section C, as required, the Company filed its annual capital expenditures report by the deadline of March 1st and included within it explanations of variances greater than both $100,000 and 10%.

- Section C of the guidelines also notes that "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". This is interpreted to refer to the variance exceeding 10% in two consecutive years. The variance was 5.66% in 2014 and 3.12% in 2015 resulting in no additional reporting requirements.

Based on our review, the Company had no reporting obligations under the Capital Budget Application Guidelines Policy #1900.6 Section B with respect to the allowance for unforeseen items as the allowance was not used during the year.

Capital Expenditure Reports

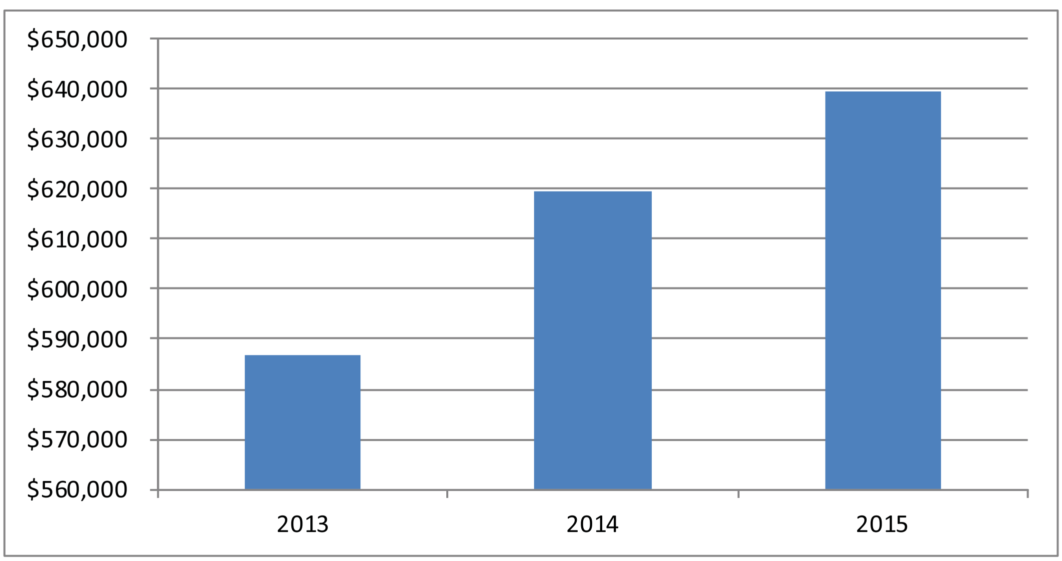
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2015 calendar year.

Revenue

Scope: Review the Company's 2015 revenue in comparison to prior years and follow up on any significant variances.

We have compared the actual revenues for 2013 to 2015 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

($000's)	**2013**	**2014**	**2015**
Residential	$ 367,550	$ 390,614	$ 403,910
General Service			
0-100 kW	81,625	82,080	85,093
110-1000 kVA	83,223	88,789	93,725
Over 1000 kVA	36,961	39,743	38,400
Streetlighting	14,633	15,262	15,541
Discounts forfeited	2,844	3,016	2,962
Revenue from rates	$ 586,836	$ 619,504	$ 639,631
Year over year percentage change	4.57%	5.57%	3.25%



The above graph demonstrates that the Company has seen a 3.25% increase in revenue from rates in 2015 as compared to 2014. The increase primarily relates to an increase in customer energy rates effective July 1, 2015 related to the Board's approval of an interim rate increase in the wholesale electricity rate charged by Newfoundland and Labrador Hydro to the Company. The remaining increase in revenue reflects higher electricity sales. There was a 0.98% increase in the overall demand in GWh for 2015. For residential sales there was an increase of 3.40% in 2015 revenue from 2014. GWh sold in this category increased by 1.14%, and the number of residential customers increased by 1.17%.

The comparison by rate class of 2015 actual revenues to 2015 budget is as follows:

($000's)	2014	2015	2015 Plan	Actual - Plan Variance	%
Residential	$ 390,614	$ 403,910	$ 397,880	$ 6,030	1.52%
General Service					
0-100 kW	82,080	85,093	83,020	2,073	2.50%
110-1000 kVA	88,789	93,725	89,857	3,868	4.30%
Over 1000 kVA	39,743	38,400	40,521	(2,121)	(5.23%)
Streetlighting	15,262	15,541	15,333	208	1.36%
Discounts forfeited	3,016	2,962	2,940	22	0.75%
Total revenue from rates	$ 619,504	$ 639,631	$ 629,551	$ 10,080	1.60%

We have also compared the 2015 budget energy sales in GWh to the actual sold in 2015:

	2014	2015	2015 Plan	Actual - Plan Variance	%
Residential	3,613.1	3,654.2	3,680.6	(26.4)	(0.72%)
General Service					
0-100 kW	782.8	792.4	795.2	(2.8)	(0.35%)
110-1000 kVA	965.1	998.3	973.1	25.2	2.59%
Over 1000 kVA	505.6	479.5	516.3	(36.8)	(7.13%)
Streetlighting	31.9	32.2	32.0	0.2	0.63%
Total revenue from rates	5,898.5	5,956.6	5,997.2	(40.6)	(0.68%)

Actual 2015 revenue from rates was higher than 2015 Plan with an overall increase in actual sales of $10,080,000 (1.60%) from the 2015 Plan. There was a 0.68% decrease in GWh sold in 2015 compared to 2015 Plan. The largest variances in revenue can be seen in the Residential and 110-1000 KVA classes where revenues increase by $6,030,000 (1.52%) and $3,868,000 (4.30%) respectively, and they are offset partially by over 1000 kVA class where actual revenues decreased by $2,121,000 (5.23%).

Operating and General Expenses

Scope: Conduct an examination of operating and general expenses to assess their reasonableness in relation to sales of power and energy and their compliance with Board Orders.

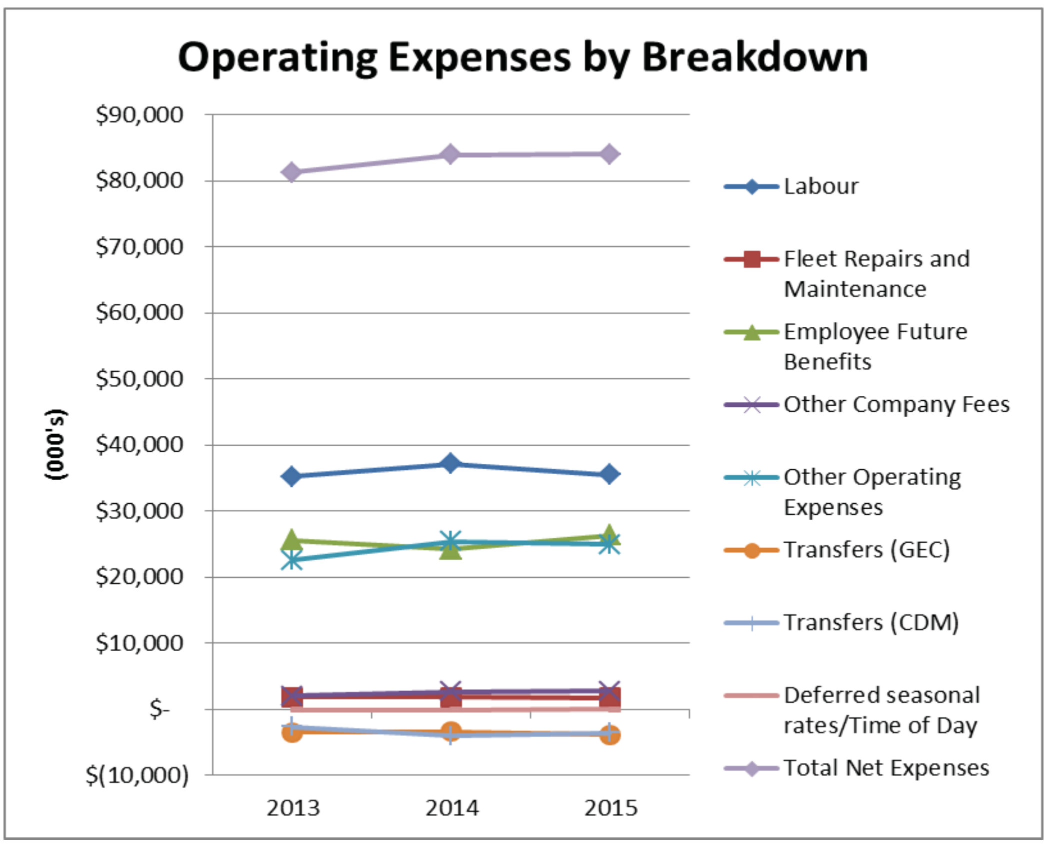
(000's)	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Labour	$ 36,485	$ 37,871	$ 35,918	$ (1,386)
Reclass OPEB labour cost	(969)	(658)	(663)	(311)
Total Labour	35,516	37,213	35,255	(1,697)
Vehicle expense	1,786	1,901	1,881	(115)
Operating materials	1,583	1,857	1,568	(274)
Inter-company charges	1,560	1,710	1,184	(150)
Plants, Subs, System Oper & Bldgs	2,367	2,312	2,153	55
Travel	1,052	1,318	1,297	(266)
Tools and clothing allowance	1,130	1,192	1,141	(62)
Miscellaneous	1,765	1,970	1,751	(205)
Conservation	2,466	1,762	1,250	704
Taxes and assessments	1,123	1,040	1,011	83
Uncollectible bills	1,313	1,490	897	(177)
Insurance	1,260	1,243	1,197	17
Severance & other employee costs	72	58	84	14
Education, training, employee fees	298	310	392	(12)
Trustee and directors' fees	462	431	397	31
Other company fees	2,757	2,650	2,024	107
Stationary & copying	230	266	308	(36)
Equipment rental/maintenance	746	769	677	(23)
Communications	3,184	3,220	3,074	(36)
Advertising	1,251	1,444	1,113	(193)
Vegetation management	1,766	1,789	1,993	(23)
Computing equipment & software	1,058	915	799	143
Total Other	29,229	29,647	26,191	(418)
Pension & early retirement program	17,702	13,276	14,744	4,426
OPEB's	8,653	10,968	10,880	(2,315)
Total employee future benefits	26,355	24,244	25,624	2,111
Total gross expenses	91,100	91,104	87,070	(4)
Transfers (GEC)	(3,809)	(3,399)	(3,415)	(410)
CDM amortization	1,053	420	339	633
Deferred CDM program costs	(4,611)	(4,436)	(2,937)	(175)
Deferred seasonal rates/TOD	(9)	(39)	(71)	30
Deferred regulatory costs	322	322	322	-
Total net expenses	$ 84,046	$ 83,972	$ 81,308	$ 74

The above table provides details of operating and general expenses (including non-regulated expenses) by "breakdown" for 2013, 2014 and 2015 Actual.

Overall, net operating expenses were relatively flat as there was only an increase of $74,000 from 2014 to 2015. Significant operating expense variances are discussed in our report. We conducted an examination of other costs including purchased power, depreciation, interest and income taxes and have noted that nothing has come to our attention to indicate that these costs for 2015 are unreasonable.

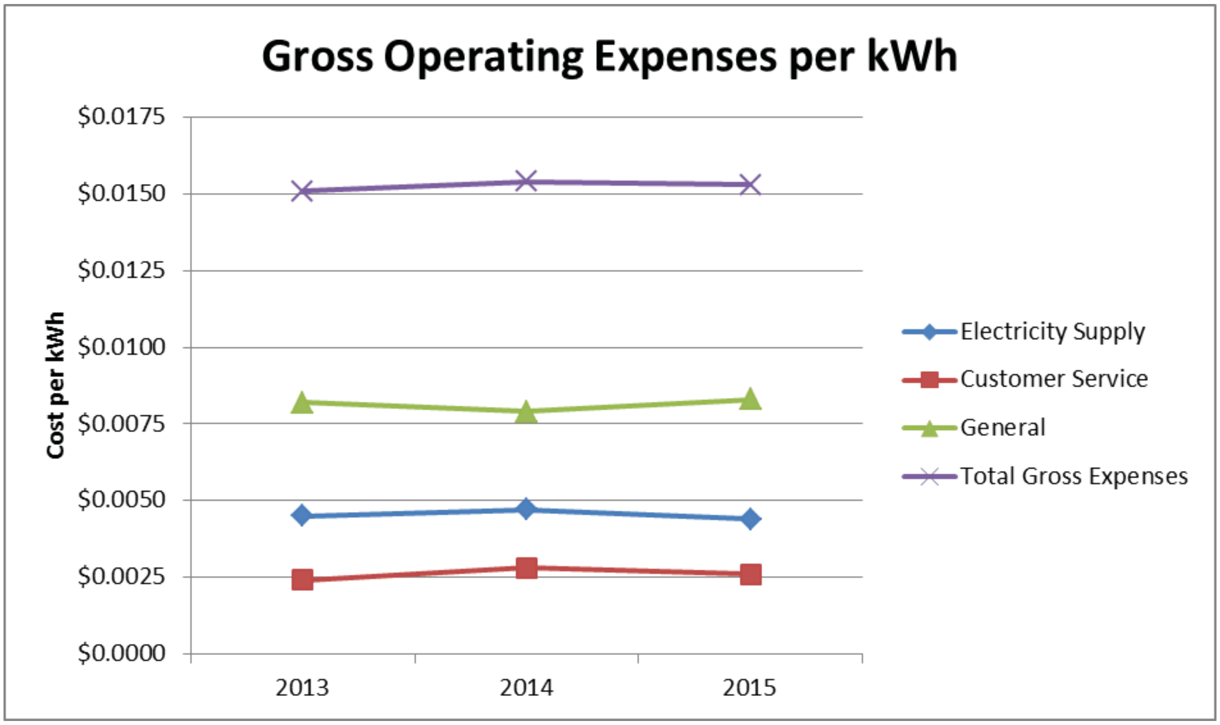
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph shows the trend in operating expenses by breakdown for the period 2013 to 2015.

	Actual		
(000's)	**2013**	**2014**	**2015**
Labour	$ 35,255	$ 37,213	$ 35,516
Fleet Repairs and Maintenance	1,881	1,901	1,786
Employee Future Benefits	25,624	24,244	26,355
Other Company Fees	2,024	2,650	2,757
Other Operating Expenses	22,608	25,418	25,008
Transfers (GEC)	(3,415)	(3,399)	(3,809)
Transfers (CDM)	(2,598)	(4,016)	(3,558)
Deferred seasonal rates/Time of Day	(71)	(39)	(9)
Total Net Expenses	$ 81,308	$ 83,972	$ 84,046



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2013 to 2015 is presented in the table below.

		Electricity Supply		Customer Service		General		Total Gross Expenses	
Year	kWh sold (000's)	Cost (000's)	Cost per kWh	Cost (000's)	Cost per kWh	Cost (000's)	Cost per kWh	Cost (000's)	Cost per kWh
2013	5,763,300	$ 26,072	$ 0.0045	$ 14,009	$ 0.0024	$ 46,989	$ 0.0082	$ 87,070	$ 0.0151
2014	5,898,500	$ 27,817	$ 0.0047	$ 16,478	$ 0.0028	$ 46,809	$ 0.0079	$ 91,104	$ 0.0154
2015	5,956,600	$ 26,191	$ 0.0044	$ 15,474	$ 0.0026	$ 49,435	$ 0.0083	$ 91,100	$ 0.0153



The table and graph show that total gross expenses per kWh have decreased by approximately 0.6% compared to 2014.

There was an increase in General Costs of $2.6 million but those costs were offset by decreases in Electricity Supply Costs and Customer Service Costs of $1.6 million and $1.0 million respectively. Our observations and findings based on our detailed review of the individual significant expense categories variances are noted below.

Salaries and Benefits (including executive salaries)

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 2013 to 2015 (including 2015 plan) is as follows:

	Actual 2015	Plan 2015	Actual 2014	Actual 2013	Actual - Plan	Actual 2015-2014
Executive Group	**6.0**	**6.0**	5.8	6.0	0.0	0.2
Corporate Office	**20.7**	**22.0**	22.3	21.0	(1.3)	(1.6)
Finance	**93.5**	**91.4**	90.9	89.1	2.1	2.6
Egineering and Operations	**418.5**	**434.5**	424.4	422.1	(16.0)	(5.9)
Customer Relations	**68.0**	**67.9**	72.9	62.0	0.1	(4.9)
	606.7	**621.8**	616.3	600.2	(15.1)	(9.6)
Temporary employees	**46.3**	**50.3**	48.5	55.6	(4.0)	(2.2)
Total	**653.0**	**672.1**	664.8	655.8	(19.1)	(11.8)

The overall number of FTE's in 2015 compared to 2014 decreased by 11.8. The budgeted number of FTE's in the 2015 Plan was 672.1 versus actual of 653.0. The variances between 2015, 2015 Plan and 2014 are the result of the following:

- The Corporate Office is lower than 2014 and 2015 plan primarily due to the timing of retirements and leaves of absence.
- Finance is higher than 2014 due primarily to increased resources required for information systems and infrastructure support including supervisory control and data acquisition (SCADA) and geographic information systems (GIS).
- Engineering and operations is lower than Plan 2015 and 2014 actual due primarily to timing of retirements and leaves of absence, labour efficiencies and transfers of employees to other departments.
- Customer Relations is lower than 2014 actual due primarily to timing of retirements and leaves of absence partially offset by the expansion of customer energy conservation programming
- Temporary Employees are lower than both 2014 and Plan 2015 due primarily to labour efficiencies including the implementation of the Automated Meter Reading (AMR) strategy and a shift of temporary positions to fulltime.

An analysis of salaries and wages by type of labour and by function from 2013 to 2015 is as follows:

(000's)	**Actual 2015**	Actual 2014	Actual 2013	**Variance 2015-2014**
Type				
Internal labour	**$ 63,330**	$ 62,275	$ 59,784	$ 1,055
Overtime	**5,117**	6,968	5,228	(1,851)
	68,447	69,243	65,012	(796)
Contractors	**15,232**	18,286	13,613	(3,054)
	$ 83,679	$ 87,529	$ 78,625	$ (3,850)
Function				
Operating	**$ 36,485**	$ 37,871	$ 35,918	$ (1,386)
Capital and miscellaneous	**47,194**	49,658	42,707	(2,464)
Total	**$ 83,679**	$ 87,529	$ 78,625	$ (3,850)
Year over year percentage change	-4.40%	11.32%	6.54%	

Our review of salaries and benefits included an analysis of the year to year variances, consideration of trends in labour costs, and discussion of the significant variances with Company officials. As indicated in the above table, total labour costs for 2015 were $3,850,000 (-4.40%) lower than 2014.

Internal labour costs in 2015 were higher than 2014 by 1.70% primarily due to normal salary increases partially offset by a reduction in full time equivalents.

Overtime in 2015 was lower than 2014 as 2014 included increased labour costs required for restoration and customer service response following the loss of generation supply from Hydro, increased peak load management, inclement weather conditions and a higher number of trouble calls.

Contract labour was lower than 2014 due primarily to decreased distribution work associated with the Bell Island Cable replacement.

As part of our review we completed an analysis of the average salary per FTE, including and excluding executive compensation (base salary and short term incentive). The results of our analysis for 2013 to 2015 are included in the table below:

Salary Cost Per FTE

	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Total reported internal labour costs	**$ 63,330**	$ 62,275	$ 59,784	$ 1,055
Benefit costs (net)	**(7,559)**	(7,448)	(7,502)	(111)
Other adjustments	**(605)**	(646)	(571)	41
Base salary costs	**55,166**	54,181	51,711	985
Less: executive compensation	**(1,750)**	(1,932)	(1,893)	182
Base salary costs (excluding executive)	**$ 53,416**	$ 52,249	$ 49,818	$ 1,167
FTE's (including executive members)	**653.0**	664.8	655.8	
FTE's (excluding executive members)	**649.0**	661.0	651.8	
Average salary per FTE	**84,481**	81,500	78,952	
% increase	**3.66%**	3.36%	3.71%	
Average salary per FTE (excluding executive members)	**82,305**	79,045	76,531	
% increase	**4.12%**	3.42%	3.68%	

The above analysis indicates that for 2015 the rate of increase in average salary per FTE has been fairly consistent from 2013 to 2015.

During 2014, the Company negotiated a new collective agreement with its union that was ratified in 2015.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2013 to 2015 and the targets set for 2015:

Measure	Target 2015	Actual 2015	Actual 2014	Actual 2013
Controllable Operating Costs/Customer	**$231.60**	$219.80	$223.90	$217.60
Earnings	**37.7m**	38.8m	37.3m	36.5m
Reliability - Duration of Outages (SAIDI)	**2.30**	2.36	2.44	2.23
Customer Satisfaction - % Satisfied	**84.7%**	86.1%	83.5%	85.9%
Injury Frequency Rate	**0.69**	0.18	0.51	0.52
Regulatory Performance	**Subjective**	140%	150%	150%

2015 STI results were adjusted to remove the impact of the loss of supply from Hydro in March. In 2013, First Call Resolution was replaced with Regulatory Performance. The Company indicated that Regulatory Performance is evaluated on a subjective basis as it is difficult to apply statistical or cost based analyses. For 2015, the key determinants of the result of 140% were as follows: (i) the company's participation in the Board's investigation into system reliability initiated in 2014. Newfoundland Power played an active role in both phases of the Board's Investigation in 2015. For Phase One this included (1) responding to the Board in relation to the conclusions and recommendations of the Board's consultant, (2) testifying before the Board in the Phase One hearing, and (3) final written submissions. For Phase Two, Newfoundland Power engaged a consultant and issued requests for information to better understand reliability once the Muskrat Falls project is integrated into the island interconnected system. (ii) the 2016 capital budget application, and (iii) the Company's efforts in participating in Newfoundland & Labrador Hydro's Amended General Rate Application and the Newfoundland Power General Rate Application.

The Company's STI program also includes an individual performance measure for Executives and Directors. This measure is used to reinforce the accountability and achievement of individual performance targets.

The weight between corporate performance and individual performance differs between the managerial classifications, as outlined in the following table.

Classification	Corporate Performance	Individual Performance
President and CEO	70%	30%
Executives	50%	50%
Directors	50%	50%

The individual measures of performance for Directors are developed in consultation with the individuals and their respective executive member. Performance measures for the executive members, President and CEO are approved by the Board of Directors. Each measure is reflective of key projects or goals, and focuses on departmental or divisional priorities.

The program operates to provide 100% payout of established STI pay if the Company meets, on average, 100% of its performance targets. The STI pay for 2015 is established as a percentage of base pay for the three employee groups. For 2015, measures relating to 'controllable operating costs/customer', 'earnings', 'safety', 'regulatory performance' and 'customer satisfaction' metrics were met, however "SAIDI" metrics fell below target.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2013 to 2015:

	Target 2015	Actual 2015	Target 2014	Actual 2014	Target 2013	Actual 2013
President	50%	64.90%	40-50%	64%	50%	70%
Executive	40%	51.90%	35%	44.8%	35-40%	52.1%
Directors	15%	19.60%	15%	19.2%	15%	21.2%

STI actual payout rates for 'President', 'Executive' and 'Director' employee groups are higher than in the prior year and each payout rate exceeded target consistent with 2014 and 2013.

In dollar terms, the STI payouts for 2013 to 2015 are as follows:

	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
President	**$ 227,000**	$ 360,000	$ 294,000	$ (133,000)
Executive	**401,000**	312,000	404,000	89,000
Directors	**342,200**	320,300	302,000	21,900
Total	**$ 970,200**	$ 992,300	$ 1,000,000	$ (22,100)
Year over Year % change	-2.23%	-0.77%	7.3%	

In accordance with P.U. 19 (2003) the Company has classified STI payouts in excess of 100% of target as a non-regulated expense. In 2015, the non-regulated portion (before tax adjustment) was $224,170 (2014 - $272,588).

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2013 to 2015.

	Base Salary	Short Term Incentive	Other	Total
2015				
Total executive group	$ 1,122,000	$ 628,000	$ 106,244	$ 1,856,244
Average per executive (4)	**$ 280,500**	**$ 157,000**	**$ 26,561**	**$ 464,061**
2014				
Total executive group	$ 1,268,257	$ 672,000	$ 131,845	$ 2,072,102
Average per executive (4)	**$ 317,064**	**$ 168,000**	**$ 32,961**	**$ 518,026**
2013				
Total executive group	$ 1,195,019	$ 698,000	$ 126,744	$ 2,019,763
Average per executive (4)	**$ 298,755**	**$ 174,500**	**$ 31,686**	**$ 504,941**
% Average decrease 2015 vs 2014	-11.53%	-6.55%	-19.42%	-10.42%

Base salary for the executive group in 2015 decreased from 2014 primarily due to the fact that there were salary decreases for the newly appointed President & CEO as at August 1, 2014 and the Vice President, Customer Operations & Engineering as at October 29, 2014. Also, the executive salary information provided by Newfoundland Power for the 2014 year included the management salary of the Vice President of Customer Operations & Engineering who was promoted to the role as at October 29, 2014. Base salaries have been agreed to the 2016 Board of Directors' minutes, and STI payouts have been agreed to the 2016 Board of Directors' minutes.

Company Pension Plan

For 2015, we reviewed the accounts supporting the gross charge of $17,702,000 of pension expense for the Company. A detailed comparison of the components of pension expense for 2013 to 2015:

	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Pension expense per actuary	**$15,332,000**	$ 11,084,000	$ 12,744,000	$ 4,248,000
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**562,000**	568,000	560,000	(6,000)
Group RRSP @ 1.5%	**384,000**	422,000	440,000	(38,000)
Individual RRSP's	**1,421,000**	1,211,000	1,013,000	210,000
Less: Refunds (net of other expenses)	**3,000**	(9,000)	(13,000)	12,000
Total	**$17,702,000**	$ 13,276,000	$ 14,744,000	$ 4,426,000
Year over year percentage change	**33.34%**	(9.96%)	14.33%	

Overall, pension expense for 2015 is higher than 2014 primarily due to a lower discount rate at December 31, 2014, which is used to determine the pension obligation for 2015.

The Company's pension uniformity plan is meant to eliminate the inequity in the regular pension plan related to the limitation on the maximum level of contributions permitted by income tax legislation. In effect, the pension uniformity plan tops up the benefits for senior management so that they receive benefits equivalent to the benefit formula of the registered pension plan. The Board ordered in P.U. 7 (1996-97) that the pension uniformity plan is allowed as reasonable, prudent and properly chargeable to the operating account of the Company. The PUP and SERP expenses decreased by 1.06% in 2015.

The employer's portion of the contributions to the Group RRSP is calculated as 1.5% of the base salary paid to the plan participants. Individual RRSP contributions increased by 17.3% as a result of the closure of the Company's Defined Benefit Plan in 2004. New hires are added to the Individual RRSP Plan whereas the majority of retirements and terminations are out of the Group RRSP Plan. The actual increase of approximately $172,000 in overall RRSP contributions (Group and Individuals) made by the employer in comparison to 2014 was primarily the result of wage increases and new hires in the year, which was partially offset by retirements and terminations (35 retirements in 2015). The net increase for RRSP expenditures in 2015 is due to new hires in the 5.75% Plan who are replacing retired employees in the 1.5% Plan. Over the last few years, changes in the Company's workforce have resulted in a decrease in Group RRSP costs (as those individuals retire) and an increase in the individual RRSP (resulting from new hires).

Other Post-Employment Benefits ("OPEBs")

In its 2010 General Rate Application, the Company proposed the implementation of the accrual method of accounting for OPEBs expenses. The proposal included a deferral mechanism to capture annual variances arising from changes in the discount rate and other assumptions, and recommendations related to the recovery of the transitional balance associated with the adoption of accrual accounting for OPEBs costs. In P.U. 31 (2010) the Board decided the Company should use the accrual method of accounting for OPEBs costs and income tax related to OPEBs as of January 1, 2011.

The Board also required that the transitional balance for OPEBs expense be amortized using the straight-line method over a period of 15 years. The Board also approved the creation of the OPEBs Cost Variance Deferral Account to limit the variability of the OPEBs costs due to changing assumptions such as discount rates.

The components of OPEBs expense for 2013 to 2015 are as follows:

(000's)	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Accrued OPEBs	**$ 6,055**	$ 8,038	$ 7,957	$ (1,983)
Amortization of transitional balance	**3,504**	3,504	3,504	-
Amount capitalized	**(906)**	(574)	(581)	(332)
Total	**$ 8,653**	$ 10,968	$ 10,880	$ (2,315)

According to the company, the lower OPEBs costs in 2015 reflect a reduction in claims cost experience under the plan as determined in the actuarial report.

Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with P.U. 19 (2003), P.U. 32 (2007), P.U. 43 (2009), and P.U. 13 (2013);
- compared intercompany charges for the years 2013 to 2015 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2015 and investigated any unusual items;
- vouched a sample of transactions for 2015 to supporting documentation;
- assessed the appropriateness of the amounts being charged; and,
- reviewed the methodology developed by Fortis Inc. in 2008 to allocate recoverable expenses to its subsidiaries.

The following table summarizes intercompany transactions from 2013 to 2015 for charges to and from Newfoundland Power Inc.:

	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Charges from related companies				
Regulated	**$ 208,781**	$ 311,536	$ 203,300	$ (102,755)
Non-Regulated	**1,672,009**	1,990,723	1,467,175	(318,714)
Total	**$ 1,880,790**	$ 2,302,259	$ 1,670,475	$ (421,469)
Charges to related companies	**$ 229,125**	$ 336,758	$ 506,639	$ (107,633)

Fortis bills its recoverable expenses on estimates rather than actual for the first three quarters of each year. For the fourth quarter, a true-up calculation is completed to reflect actual recoverable expenses incurred during the year. Recoverable expenses are allocated among the subsidiaries based on actual results.

The majority of the recoverable expenses from Fortis Inc. relate to non-regulated expenses.

We reviewed Fortis Inc.'s methodology to estimate its recoverable expenses over the first three quarters as well as its "true up" calculation for the 4th quarter. We noted during our review that Fortis Inc. continues to allocate its recoverable costs based on its subsidiaries' assets. There were no changes to the methodology in 2015.

- Fortis Inc. estimated its net pool of operating expenses for 2015 in Q4 2014 as part of its annual business planning process and determined its estimated billings based on the pro-rata portion of such net costs using the estimated assets of subsidiaries. For Quarters 1 through 3 Fortis Inc. billed evenly based upon 25% of the estimated annual amount.
- For the fourth quarter, a true-up calculation is completed to reflect actual expenses incurred during the year. Fortic Inc. used the average actual assets for the first 3 quarters and forecast 4th quarter in this calculation. Since regulated expenses are fairly consistent from month to month, the estimate in the 4th quarter expenditures had a minimal impact.

During the fourth quarter of 2015, a "true up" calculation was completed to reflect actual recoverable expenses which were determined to be $1,560,000 and are summarized as follows:

2015 Recoverable Expenses from Fortis Inc.

	Amount	
Staffing and Staffing Related	$944,000	Non-regulated
Director Fees	114,000	Non-regulated
Consulting and Legal fees	137,000	Non-regulated
Trustee Agent Fees	35,000	Regulated
Audit and Other Fees	33,000	Non-regulated
Public Reporting Costs	40,000	Non-regulated
Annual Meeting Expenses	37,000	Non-regulated
Travel (Board and Other)	52,000	Non-regulated
Insurance (D&O)	21,000	Non-regulated
Other Costs	147,000	Non-regulated
	1,560,000	
Less amounts previously billed:		
Q1 2015	453,000	
Q2 2015	453,000	
Q3 2015	453,000	
Q4 2015 balance owing	$ 201,000	

For 2015, Newfoundland Power's percentage allocation of Fortis Inc. corporate costs was 5.65%, down from 7.43% in 2014.

As detailed above, trustee agent fees for $35,000 were the only expenses allocated to regulated operations by the Company relating to recoverable expenses. Certain other direct costs were recovered by Fortis Inc. by separate invoicing throughout the year and are detailed in the analysis below of regulated and non-regulated operations.

The analysis below is a review of the intercompany variances related to charges to and from Fortis Inc. as well as other related parties. The following table summarizes the various components of the regulated intercompany transactions for 2013 to 2015 with Fortis Inc.:

Intercompany Transactions

(Regulated)	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Charges from Fortis Inc.				
Trustee fees and share plan costs	**$ 35,000**	$ 48,000	$ 53,000	$ (13,000)
Miscellaneous	**24,472**	128,593	14,185	(104,121)
Staff Charges	**19,756**	-	-	19,756
	$ 79,228	$ 176,593	$ 67,185	$ (97,365)
Year over year percentage change	**(55.14%)**	162.85%	2.79%	
Charges to Fortis Inc.				
Printing and stationery	**$ 2,191**	$ 76	$ -	$ 2,115
Postage and couriers	**19,468**	25,704	24,565	(6,236)
Staff charges	**44,430**	43,667	97,979	763
Staff charges - insurance	**4,639**	38,527	183,267	(33,888)
IS Charges	**-**	-	309	-
Pole removal and installation	**-**	769	572	(769)
Miscellaneous	**7,855**	64,713	6,090	(56,858)
	$ 78,583	$ 173,456	$ 312,782	$ (94,873)
Year over year percentage change	**(54.70%)**	(44.54%)	(29.91%)	

The most significant fluctuation from our analysis of regulated charges from Fortis Inc. is within the miscellaneous account of a decrease of $104, 121. This is primarily due to the transfer of an unused vacation accrual of $108,844 being transferred to Fortis Inc. when the former CEO moved from Newfoundland Power to Fortis from 2014.

The most significant fluctuation from our analysis of regulated charges to Fortis Inc. is a $56,858 decreases in miscellaneous. This is primarily a result of 2014 actual reflecting the sale of the former CEO's vehicle for $53,089 to Fortis Inc.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2013 to 2015:

(Non-Regulated)	**Actual 2015**	**Actual 2014**	**Actual 2013**	**Variance 2015-2014**
Charges from Fortis Inc.				
Director's fees and travel	**166,000**	373,000	185,000	$ (207,000)
Annual and quarterly reports	**73,000**	98,000	90,000	$ (25,000)
Staff charges	**944,000**	849,000	558,000	$ 95,000
Miscellaneous	**489,009**	663,602	634,175	$ (174,593)
	$ 1,672,009	$ 1,983,602	$ 1,467,175	$ (311,593)
Year over year percentage change	**(15.71%)**	35.20%	(6.50%)	

Director’s fees and travel decreased by $207,000, primarily due to the decrease in Newfoundland Power’s allocation of director’s fees from Fortis Inc., mainly due to the impact of share price depreciation for 2015 compared to the share price appreciation for 2014.

Miscellaneous charges decreased by $174,593 reflect the difference in stock option expenses which were $321,000 in 2014 versus $147,000 in 2015.

The following table provides a summary and comparison of the other intercompany transactions for 2013 to 2015:

Intercompany Transactions (Other)	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Charges to Fortis Properties				
Staff charges	**$ 23,569**	$ 12,108	$ -	$ 11,461
Staff charges - insurance	**21,796**	23,753	30,894	(1,957)
Stationary costs	**-**	288	352	(288)
Miscellaneous	**500**	790	2,770	(290)
	$ 45,865	$ 36,939	$ 34,016	$ 8,926
Charges from Fortis Properties				
Hotel/Banquet facilities & meals	**$ 3,113**	$ 34,048	$ 52,961	$ (30,935)
Miscellaneous	**48,885**	1,664	1,636	47,221
	$ 51,998	$ 35,712	$ 54,597	$ 16,286
Charges to Fortis Ontario Inc.				
Staff charges - insurance	**$ 3,620**	$ 3,116	$ 4,091	$ 504
Staff charges	**5,666**	4,986	16,587	680
IS charges	**4,065**	4,208	4,080	(143)
Miscellaneous	**390**	380	370	10
	$ 13,741	$ 12,690	$ 25,128	$ 1,051
Charges to Maritime Electric				
Staff charges	**$ 6,541**	$ 3,813	$ 6,976	$ 2,728
Staff charges - insurance	**934**	1,444	1,954	(510)
IS charges	**3,048**	2,945	2,856	103
Miscellaneous	**530**	510	573	20
	$ 11,053	$ 8,712	$ 12,359	$ 2,341
Charges from Maritime Electric				
Staff charges	**$ -**	$ 34,372	$ -	$ (34,372)
Miscellaneous	**250**	-	5,614	250
	$ 250	$ 34,372	$ 5,614	$ (34,122)
Charges from Central Hudson Gas & Electric				
Miscellaneous	**$ 182**	$ 13,973	$ 4,647	$ (13,791)
Charges to Central Hudson Gas & Electric				
Staff charges - insurance	**$ -**	$ -	$ 6,702	$ -
Charges to Fortis US Energy Corp				
Staff charges - insurance	**$ -**	$ -	$ 74	$ -

Intercompany Transactions (Other) Cont'd.	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Charges to Belize Electric Company Ltd.				
Staff charges	**$ 20,779**	$ -	$ -	$ 20,779
Staff charges - insurance	**-**	648	6,177	(648)
	$ 20,779	$ 648	$ 6,177	$ 20,131
Charges to FortisAlberta Inc.				
Staff charges - insurance	**$ 39**	$ 76	$ 3,359	$ (37)
Miscellaneous	**4,260**	13,280	3,650	(9,020)
	$ 4,299	$ 13,356	$ 7,009	$ (9,057)
Charges from FortisAlberta Inc.				
Miscellaneous	**$ 49,452**	$ 37,611	$ 41,411	$ 11,841
Charges to FortisBC Inc.				
IS charges	**10,363**	11,781	11,424	(1,418)
Staff charges - insurance	**39**	-	2,768	39
Miscellaneous	**2,410**	2,342	2,363	68
	$ 12,812	$ 14,123	$ 16,555	$ (1,311)
Charges from FortisBC Inc.				
Miscellaneous	**$ 3,822**	$ 3,322	$ 8,740	$ 500
Charges to Fortis BC Holdings				
Staff charges - insurance	**$ -**	$ 648	$ 2,882	$ (648)
Miscellaneous	**6,780**	6,360	6,290	420
	$ 6,780	$ 7,008	$ 9,172	$ (228)
Charges to Caribbean Utilities Co. Limited				
Staff charges	**$ 22,219**	$ 27,113	$ 54,492	$ (4,894)
Staff charges - insurance	**-**	120	11,048	(120)
Miscellaneous	**-**	-	1,400	-
	$ 22,219	$ 27,233	$ 66,940	$ (5,014)
Charges from Caribbean Utilities Co. Limited				
Miscellaneous	**$ 23,849**	$ 17,074	$ 21,106	$ 6,775
Charges to Fortis Turks and Caicos				
Staff charges	**$ 12,271**	$ 42,391	$ -	$ (30,120)
Staff charges - insurance	**-**	162	9,477	(162)
Miscellaneous	**723**	40	248	683
	$ 12,994	$ 42,593	$ 9,725	$ (29,599)

The most significant fluctuations from our analysis of other intercompany charges for 2015 compared to 2014 are as follows:

- Hotel/Banquet facilities and meal charges decreased by $30,935 from Fortis Properties, which is related to the 2014 Newfoundland Power's Christmas dinner and dance held at the Delta Hotel in St. John's.
- Miscellaneous charges from Fortis Properties increased by $47,221, which reflects the charges associated with a Fortis Properties employee's secondment to Newfoundland Power's Corporate Communication department in 2015.
- Staff charges from Maritime Electric decreased by $34,372, due to 2014 required labour and travel expenses for line crews who assisted in power restoration efforts in January 2014.
- Staff charges increased by $20,779 to Belize Electric Company Ltd. relating to two Newfoundland Power personnel who supplied audit, engineering and technological consultation services to Belize Electric.
- Staff Charges to Fortis Turks and Caicos decreased by $30,120, which is related to two Newfoundland Power personnel supplied services to Fortis Turks and Caicos during 2015 versus five during 2014.

The Company entered into the following short term loan agreements with related parties during the year:

Lender		Maximum Amount Borrowed	Date Borrowed	Date Repaid	Interest Rate		Total Interest Cost [1]
Fortis Inc.	$	10,000,000	April. 20, 2015	April. 30, 2015	2.450%	$	6,712
Fortis Inc.		5,000,000	May. 20, 2015	May. 27, 2015	2.450%		2,349
Fortis Inc.		10,500,000	October. 20, 2015	October. 28, 2015	1.188%		1,543
Fortis Inc.		10,000,000	November. 20, 2015	December. 8, 2015	1.216%		5,129
	$	35,500,000				$	15,733

[1] - Interest charged by Fortis is charged at a discount price and includes a stamp fee.

The interest rates charged on each of the loans above were lower than what would have been charged under the Company's debt facilities. In April and May, the Company had borrowed the maximum of $100 million from their committed credit facility which meant that any further borrowings would have been done from their demand facility at an interest rate of 2.85%, which were provided by Fortis Inc. at an interest which was 0.40% lower. Likewise, the interest rates which would have been charged under the Committed Credit facility for each of the loans in October and November would have been 0.412% and 0.414% higher respectively.

In Order P.U. 19 (2003), the Board provided instructions to the Company with respect to the recording and reporting of intercompany transactions. Some of these instructions required reports to be filed with the Board at various times in 2015. Confirmation was received from the Board that quarterly reports relating to intercompany transactions have been filed for 2015.

In Order P.U. 32 (2007), the Board ordered the Company to file a fair market value determination for insurance services provided by the Company to its affiliates, including an appropriate charge-out rate. As a result of this filing, a derived proxy market rate of $108 per hour was determined by the Company compared with a previous charge out rate of $78.97 based on a fully distributed cost methodology. The $108 per hour charge out rate was effective April 1, 2008. There was no change in the rate as a result of the 2013/14

General Rate Application. We reviewed a sample of insurance charges to subsidiaries for each quarter of 2015 and noted some exceptions. Staff charges relating to routine insurance matters (e.g.; coverage queries, damage claims, arranging for insurance certificates) are based on the recovery of fully distributed costs (hourly rate plus 70% markup). The Company noted that they believe this policy to be accordance with Section 6.5 of the Inter-Affiliate Code of Conduct (May 2011) submitted to the Board on June 10, 2011. These charges were further investigated to determine the impact of using a lower rate. It was determined that had the Company charged $108 per hour rather than the fully distributed cost, an additional $12,000 in staff insurance charges to related parties would result in 2015.

As a result of completing our procedures in this area, nothing came to our attention that would lead us to believe that intercompany charges are unreasonable.

Other Company Fees and Deferred Regulatory Costs

The procedures performed for this category included a review of the transactions for 2015 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Other company fees				
Other company fees	$ 1,601	$ 1,791	$ 1,648	$ (190)
Regulatory hearing costs	1,156	859	376	297
	$ 2,757	$ 2,650	$ 2,024	$ 107
Year over year percentage change	4.0%	30.9%	-18.6%	
Deferred regulatory costs				
Total deferred regulatory costs	$ 322	$ 322	$ 322	$ -
Year over year percentage change	0.0%	0.0%	27.3%	

Total company fee costs for 2015 were higher than 2014 actual by $107,000. These costs were higher than 2014 due primarily to increased regulatory activity partially offset by lower consultant costs for customer energy conservation programming in 2015. Deferred regulatory costs are discussed in the section of the report relating to regulatory assets and liabilities.

As noted in prior annual reviews, this category of costs often experiences significant fluctuations from year to year. In addition, the costs in this category generally relate to projects which are often non-recurring by nature. Consequently, we continue to recommend that this category be monitored closely on an annual basis.

Miscellaneous

The breakdown of items included in the miscellaneous expense category for 2013 to 2015 is as follows:

(000's)	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Miscellaneous	**$ 967**	$ 1,164	$ 1,048	$ (197)
Cafeteria and lunchroom Supplies	**84**	92	95	(8)
Promotional items	**152**	120	119	32
Computer Software	**2**	5	5	(3)
Damage claims	**301**	259	241	42
Community relations activities	**3**	1	11	2
Donations and charitable advertising	**188**	263	172	(75)
Books, magazines and subscriptions	**35**	33	33	2
Misc. lease payments	**33**	33	27	-
Total miscellaneous expenses	**$ 1,765**	$ 1,970	$ 1,751	$ (205)
Year over year percentage change	**-10.41%**	12.51%	7.82%	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2014 to 2015 these expenses have decreased by 10.41% overall, primarily due to the fact 2014 included increased customer energy conservation programming materials and higher non-regulated donations.

Our procedures in this expense category for 2015 included vouching a sample of transactions within the "miscellaneous category" to supporting documentation. Based upon the results of our procedures nothing has come to our attention to indicate that the 2015 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with P.U. 7 (1996-97), the Company filed the 2015 Conservation and Demand Management Report with the Board. This report provided a summary of 2015 CDM activities and costs as well as the outlook for 2015.

In 2015, the Company and Newfoundland and Labrador Utilities completed work on an updated Conservation Potential Study ("CPS") for Newfoundland and Labrador. The primary outcomes of this CPS were the identification of cost-effective energy and demand reduction measures, general parameters for program development, and quantification of achievable energy savings potential by sector and end-use.

In 2015, the Utilities also finalized the joint Five-Year Conservation Plan: 2016-2020 (the "2016 Plan") which builds on the Utilities' experience, and continues to reflect the principles underlying two previous joint, multi-year conservation plans. It reflects refinement of the opportunities identified in the CPS through in-depth local market research and program cost benefit analysis.

Total CDM costs in 2015 totaled $5,736,000 compared to $5,588,000 in 2014, a $148,000 increase. There was an increase in costs for Small Technologies and the Business Efficiency Program but these increases were partially offset by a decrease in Windows costs as the Windows program ended in December 2014.

In 2015, $4,611,000 ($3,274,000 after tax) in CDM costs were deferred to be amortized over 7 years as per P.U. (2013).

Based upon the results of our procedures we concluded that CDM is in compliance with Board Orders.

Other Operating and General Expense Categories

In addition to the various categories of expenses commented on above, the other categories of operating and general expenses by breakdown were also analyzed for any unusual variances between 2015 and 2014.

(000's)	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Vehicle expense	1,786	1,901	1,881	(115)
Operating materials	1,583	1,857	1,568	(274)
Plants, Subs, System Oper & Bldgs	2,367	2,312	2,153	55
Travel	1,052	1,318	1,297	(266)
Tools and clothing allowance	1,130	1,192	1,141	(62)
Conservation	2,466	1,762	1,250	704
Taxes and assessments	1,123	1,040	1,011	83
Uncollectible bills	1,313	1,490	897	(177)
Severance and other employee costs	72	58	84	14
Insurance	1,260	1,243	1,197	17
Education, training, employee fees	298	310	392	(12)
Trustee and directors' fees	462	431	397	31
Stationary & copying	230	266	308	(36)
Equipment rental/maintenance	746	769	677	(23)
Communications	3,184	3,220	3,074	(36)
Advertising	1,251	1,444	1,113	(193)
Vegetation management	1,766	1,789	1,993	(23)
Computing equipment & software	1,058	915	799	143
Transfers (GEC)	(3,809)	(3,399)	(3,415)	(410)
CDM amortization	1,053	420	339	633
Deferred seasonal rates/TOD	(9)	(39)	(71)	30

From this analysis and from explanations provided by the Company, the following observations were made with respect to the more significant fluctuations:

- Vehicle operating costs for 2015 were lower than 2014 primarily due to lower fuel prices
- Operating materials were lower than 2014 primarily due to higher maintenance costs related to the Topsail penstock repairs in 2014
- Travel was lower than 2014 due to reduced employee travel in 2015 and lower employee relocation costs
- Conservation costs increased from 2014 due to increased customer energy conservation incentives
- Uncollectible bills costs were lower than 2014 actual as weather conditions in the winter of 2014 contributed to the increase in uncollectable bills in that year.
- Advertising costs were lower than 2014 due primarily to lower advertising costs for customer energy conservation programming.
- Computing equipment & software costs increased from 2014 primarily due to increases in 3rd party software licensing and maintenance costs associated with the Company's information systems.
- Transfers to General Expenses Capitalized (GEC) for 2015 were higher than 2014 due primarily to higher pension costs.

- Conservation and Demand Management (CDM) amortization has increased from 2014. In 2013, the Board approved the deferred recovery, over a 7 year period, of annual costs associated with expansion of customer energy conservation programming. Amortization of this deferral commenced in 2014 and is higher in 2015 due to the inclusion of the second year of deferred customer energy conservation programming costs.

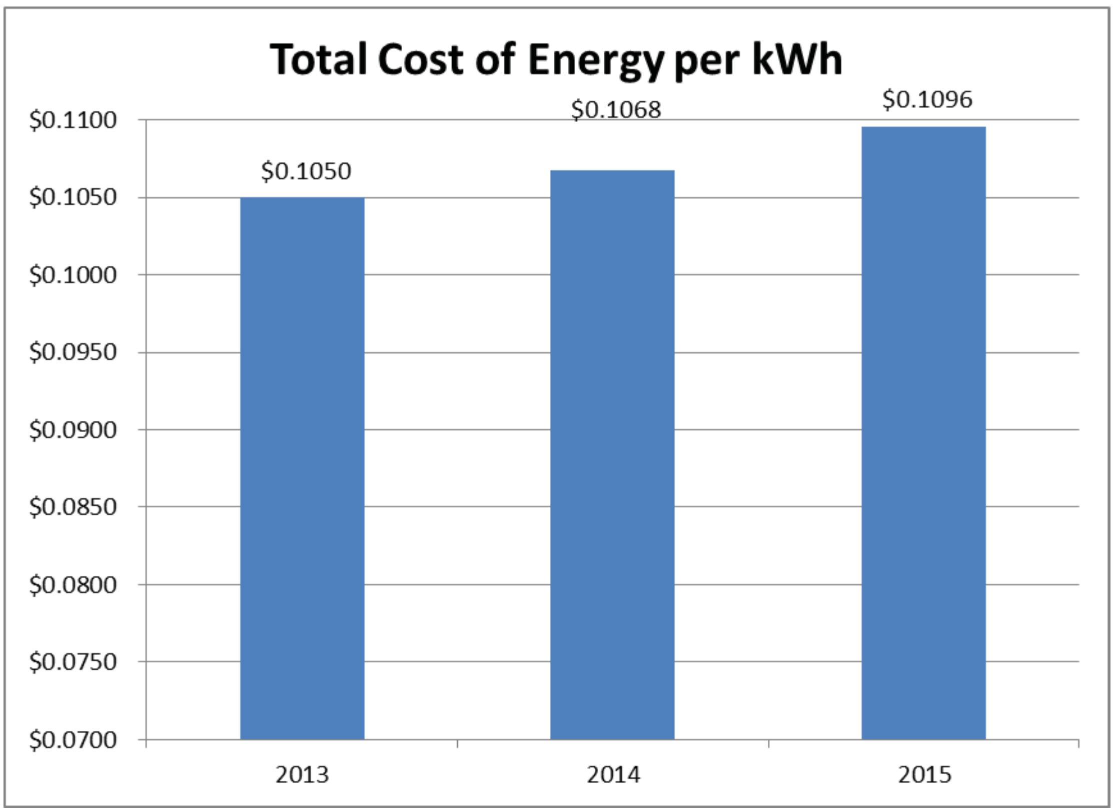
Other Costs

Scope: *Conduct an examination of purchased power, depreciation, interest and income taxes to assess their reasonableness and prudence in relation to sales of power and energy and their compliance with Board Orders.*

The following table and graph provide the total cost of energy (expressed in kWh) from 2013 to 2015:

000's

Year	kWh sold (000's)	Operating Expenses	Purchased Power	Deferred Cost Recoveries and Amortizations	Depreciation	Finance Charges	Income Taxes	Net Earnings	Total Cost of Energy	Cost per kWh
2013	5,763,300	$ 81,308	$ 390,210	$ (768)	$ 51,300	$ 36,034	$ (2,877)	$ 49,920	$ 605,127	$ 0.1050
2014	5,898,500	$ 83,972	$ 402,843	$ 3,990	$ 53,882	$ 36,450	$ 10,795	$ 37,840	$ 629,772	$ 0.1068
2015	5,956,600	$ 84,046	$ 422,095	$ 3,990	$ 56,720	$ 35,724	$ 10,925	$ 39,314	$ 652,814	$ 0.1096



Purchased Power

We have reviewed the Company's purchased power expense for 2015 and have investigated the reasons for any fluctuations and changes. We performed a recalculation of the purchased power to ensure that the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro is consistent with the established rates provided and found no errors.

Purchased power expense increased by $19.3 million, from $402.8 million in 2014 to $422.1 million in 2015. According to the Company, the increase resulted primarily from electricity sales growth and the interim rate increase in the wholesale electricity rate charged by Hydro to Newfoundland Power effective July 1, 2015. These increases were partially offset by a reduction in purchased power expense due to higher generation than water inflows at the Company's hydroelectric generating facilities.

Depreciation

We have reviewed the Company's rates of depreciation and assessed its compliance with the Gannett Fleming Depreciation Study based on plant in service as of December 31, 2010 and assessed the reasonableness of depreciation expense.

In P.U. 32 (2007) the Board ordered the Company to file a new depreciation study related to plant in service as of December 31, 2010, no later than December 31, 2011. The study for plant in service as of December 31, 2010 was completed in 2011. The study was included in the 2013-2014 General Rate Application by the Company and was approved in P.U. 13 (2013), including the approval of the accumulated depreciation reserve variance of $2.6 million to be amortized over the average remaining service life of the related assets. The depreciation rates from the 2010 depreciation study, including the amortization of the accumulated depreciation reserve, were implemented effective January 1, 2013.

Gannett Fleming has recommended the continued use of the straight line equal life group ("ELG") method in its 2010 depreciation study as this method provides for a better match of depreciation expense and loss in service.

The objective of our procedures in this section was to ensure that the 2015 depreciation amounts and rates are in compliance with Board Orders, and in agreement with the recommendations of the 2010 Depreciation Study undertaken by Gannett Fleming, Inc.

The specific procedures which we performed on the Company's depreciation expense included the following:

- agreed all depreciation rates to those recommended in the depreciation study;
- recalculated the Company's depreciation expense for 2015; and,
- assessed the overall reasonableness of the depreciation for 2015.

Amortization expense for 2015 is $56,720,000 as compared to $53,882,000 for 2014, representing a 5.27% increase. The 2015 and 2014 depreciation expense excludes the impact of the income tax deduction resulting from the cost of the removal of property, plant and equipment. The following table reconciles the depreciation as reported in the financial statements and the depreciation of fixed assets:

($000's)	**2015**	**2014**	**Variance 2015-2014**	**%**
Depreciation and amortization as reported	$ 56,720	$ 53,882	$ 2,838	**5.3%**
Less: Tax on Cost of Removal (1)	(4,869)	(4,594)	(275)	**6.0%**
Depreciation of Fixed Assets	$ 51,851	$ 49,288	$ 2,563	**5.2%**

Note 1: Recognized as income tax for financial reporting purposes

The following table provides a comparison of the depreciation of fixed assets for 2015, 2014 and 2013:

($000's)	**2015**	**2014**	**2013**	**Variance 2015-2014**	**Variance 2014-2013**
Depreciation of Fixed Assets	$ 51,851	$ 49,288	$ 46,964	$ 2,563	$ 2,324

Depreciation of fixed assets for 2015 is $51,851,000 as compared to $49,288,000 for 2014, representing a 5.2% increase. The change is attributable to an increase of depreciable assets by approximately $73,145,000.

Based on our review of depreciation expense, we conclude that the Company is in compliance with P.U. 19 (2003), P.U. 39 (2006), P.U. 32 (2007) and P.U. 13 (2013), as well as the recommendations and results of the Gannett Fleming Depreciation Study reported on the plant in service as of December 31, 2010 have been incorporated into the Company's depreciation calculations for 2015.

Finance Charges

Our procedures with respect to interest on long term debt and other interest included a recalculation of interest charges and assessment of reasonableness based on debt outstanding.

The following table summarizes the various components of finance charges expense for the years 2013 to 2015:

(000's)	Actual 2015	Actual 2014	Acutal 2013	Variance 2015-2014
Interest				
Long-term debt	**$ 35,020**	$ 36,327	$ 35,123	$ (1,307)
Other	**1,139**	645	1,092	494
Amortization				
Debt costs	**242**	254	302	(12)
Interest charged to construction	**(677)**	(776)	(483)	99
Total Finance charges	**$ 35,724**	$ 36,450	$ 36,034	$ (726)
Year over year percentage change	**-1.99%**	1.15%	0.50%	

In the above table, finance charges decreased by approximately $0.7 million, from $36.4 million in 2014 to $35.7 million in 2015. The lower finance costs reflect interest savings associated with the maturity of $29 million, 10.55% first mortgage sinking fund bonds on August 1, 2014. These savings were partially offset by interest costs associated with the $75 million, 4.446% first mortgage sinking fund bonds issued in September 2015 and higher short-term borrowings in 2015.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2015 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2015 and have noted that the effective income tax rate decreased from 22.2% in 2014 to 21.7% in 2015. 2015 and 2014 results in the following effective rates:

	2015	2014	2015-2014
Income tax expense	$ 10,925	$ 10,795	$ 130
Earnings before income tax	$ 50,239	$ 48,635	$ 1,604
Effective income tax rate	21.7%	22.2%	-0.5%

The effective rate decreased by 0.5% in 2015 compared to 2014. The primary reason for this was that there was an increase in items capitalized for accounting purposes but expensed for income tax purposes in 2015. There was no change in the statutory tax rate for 2014 and 2015 which remained at 29%.

Based upon our review of the Company's calculations, and considering the impact of timing differences, nothing has come to our attention to indicate that income tax expense for 2015 is unreasonable.

Costs Associated with Curtailable Rates

In P.U. 7 (1996-97), the Board ordered that beginning January 1, 1997; all costs associated with curtailable rates shall be charged to regulated expenses, and not to the Rate Stabilization Account. The Board ordered that the demand credit for curtailment continue at $29/kVA until April 30, 1998. In P.U. 30 (1998-99), the Board ordered that this rate be extended until a review of the curtailment service option is presented at a public hearing. In P.U. 19 (2003) the Board accepted the recommendations of the parties, as set out in the Mediation Report, that the use of the Curtailable Service Option Credit of $29/kVA be retained as is until a change in Hydro's wholesale rates causes the matter to be reconsidered.

The total curtailment credits of $345,837 for the current period compare to a total of $241,622 for the same period during the previous year. The credit total for the 2014-2015 winter season is higher than the previous season's total primarily due to higher contracted load curtailment.

Prior to the winter season, the Company contacted large general service customers that could potentially participate in the Curtailable Service Option. Through the process the Company procured an additional participant with load curtailment potential of approximately 2.6 MW. This addition was partially offset by the election of two existing Option participants, representing approximately 0.7 MW in load curtailment, to not participate in the Option during the 2014-2015 winter season.

Nothing has come to our attention to indicate that the Company is not in compliance with the applicable orders of P.U. 7 (1996-97) and P.U. 30 (1998-99).

Non-Regulated Expenses

Our review of non-regulated expenses included the following specific procedures:

* assessed the Company's compliance with Board Orders;
* compared non-regulated expenses for 2015 to prior years and investigated any unusual fluctuations;
* reviewed detailed listings of expenses for 2015 and investigated any unusual items; and
* assessed the reasonableness and appropriateness of the amounts being charged.

In the calculation of rates of return the following items are classified as non-regulated:

	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Charged from Fortis Companies:				
Annual report and quarterly reports	**$ 73,000**	$ 98,000	$ 90,000	$ (25,000)
Directors' fees and travel	**166,000**	373,000	185,000	(207,000)
Hotel/Banquet Facilities	**-**	7,100	-	(7,100)
Staff charges	**944,000**	849,000	558,000	95,000
Miscellaneous	**489,000**	663,600	634,200	(174,600)
	1,672,000	1,990,700	1,467,200	(318,700)
Performance and restricted share units	**276,800**	147,400	65,000	129,400
Donations and charitable advertising	**273,700**	331,100	221,200	(57,400)
Executive short term incentive	**272,600**	285,200	257,000	(12,600)
Miscellaneous	**39,100**	46,500	32,400	(7,400)
	2,534,200	2,800,900	2,042,800	(266,700)
Less: Income Taxes	**734,900**	812,200	592,400	(77,300)
Less: Part VI.1 tax adjustment	**-**	-	12,814,000	-
Total non-regulated (net of tax)	**$1,799,300**	$ 1,988,700	$ (11,363,600)	$ (189,400)

In the table above the most significant fluctuation between 2015 and 2014 pertains to the Charges from Fortis Companies, which is a decrease of $318,700. The variance is primarily due to these amounts including executive stock option expenses of $147,009 in 2015 and $321,602 in 2014.

In compliance with P.U. 19 (2003) the Company has classified short term incentive payouts in excess of 100% of target payouts as non-regulated expense. For 2015 this represents an addition to non-regulated expenses (before tax adjustment) of $272,600 (2014 - $285,200). Details on the short term incentive payouts are included in this report under the heading Short Term Incentive (STI) Program. The income tax rate used by the Company for calculating total non-regulated expenses net of tax is 29.0% which agrees with the Company's statutory rate as identified in the 2015 annual report.

Based upon our review and analysis, nothing has come to our attention to indicate that the amounts reported as non-regulated expenses, as summarized above, are unreasonable or not in accordance with Board Orders.

Regulatory Assets and Liabilities

Scope: Conduct an examination of the changes to regulatory assets and liabilities

Regulatory Assets and Liabilities

The following table summarizes Regulatory Assets and Regulatory Liabilities for 2014 and 2015:

(000's)	2015 Actual	2014 Actual	Variance 2015-2014
Regulatory Assets			
Rate stabilization account	**$ 960**	**$ 2,342**	$ (1,382)
OPEBs asset	**35,040**	**38,544**	(3,504)
Pension deferral	**-**	**281**	(281)
Cost recovery deferral	**-**	**1,576**	(1,576)
Cost of capital cost recovery deferral	**-**	**828**	(828)
Revenue shortfall deferral	**-**	**1,586**	(1,586)
Deferred GRA costs	**-**	**322**	(322)
Conservation and demand management deferral	**10,511**	**6,953**	3,558
Optional seasonal rate revenue and cost recovery account	**60**	**97**	(37)
Employee future benefits	**113,044**	**128,237**	(15,193)
Weather normalization account	**6,212**	**46**	6,166
Deferred income taxes	**179,532**	**176,707**	2,825
	$345,359	**$357,519**	$ (12,160)
Regulatory Liabilities			
Weather normalization account	**$ -**	**$ 2,335**	$ (2,335)
Future removal and site restoration provision	**139,700**	**135,357**	4,343
Demand management incentive account	**-**	**628**	(628)
Excess earnings	**68**	**68**	-
	$139,768	**$138,388**	$ 1,380

Rate Stabilization Account

The Rate Stabilization Account ("RSA") primarily relates to changes in the cost and quantity of fuel used by Hydro to produce electricity sold to the Company. On July 1st of each year customer rates are recalculated in order to amortize the balance in the RSA as of March 31st over the subsequent 12 month period. The rates for July 1, 2015 were approved by the Board in P.U. 18 (2015).

As of December 31, 2015, there was a charge to the RSA of $3,078,500 related to the Energy Supply Cost Variance Reserve in accordance with P.U. 32 (2007) and P.U. 43 (2009), and the Wholesale Rate Change Flow-Through Account approved in P.U. 18 (2015).

Pursuant to P.U. 31 (2010) the Board approved the Company's proposal to create an Other Post-Employment Benefits Cost Variance Deferral Account (OPEBVDA) as of January 1, 2011. This account consists of the difference between the actual other post-employment benefit expense for any year from that approved for the establishment of revenue requirement from rates. The balance in this account will be transferred to the RSA on March 31 in the year in which the difference arises. As of March 31, 2015, the debit balance of $1,701,520 in the OPEBVDA account was transferred to the RSA.

Pursuant to P.U. 43 (2009) the Board approved the Company's proposal to create a Pension Expense Variance Deferral Account (PEVDA) as of January 1, 2010. This account consists of the difference between the actual pension expense in accordance with GAAP and the annual pension expense approved for rate setting purposes. The Company will charge or credit any amount in this account to the RSA as of March 31 in the year in which the difference relates. As of March 31, 2015, the balance of $4,935,256 in the PEVDA account was credited to the RSA.

Pursuant to P.U. 13 (2013) the Board approved the Company's proposal to transfer the annual balance accrued in the Weather Normalization Reserve account in the previous year to the RSA account on March 31 of the subsequent year. As of March 31, 2015 $46,339 was credited to the RSA in accordance with P.U. 13 (2013).

The RSA is also adjusted for the Demand Management Incentive Account, the Optional Seasonal Rate Revenue and Cost Recovery Account, and the amortization of deferred customer energy conservation program costs as approved by the Board.

Other Post-Employment Benefits

The Other Post-Employment Benefits ("OPEB") asset represents the cumulative difference between the OPEB expense recognized by the Company based on the cash basis and the OPEB expense based on accrual accounting required under Canadian Generally Accepted Accounting Principles ("GAAP"). In P.U. 43 (2009) the Board ordered that the Company file a comprehensive proposal for the adoption of the accrual method of accounting for OPEB costs as of January 1, 2011. The report was filed by Newfoundland Power on June 30, 2010. In summary, the Board ordered the approval, for regulatory purposes, of the accrual method of accounting for OPEBs costs and income tax related to OPEBs; recovery of the transitional balance, or regulatory asset, of $52.4 million as at January 1, 2011, over a 15-year period; and adoption of the OPEB Cost Variance Deferral Account. These recommendations were approved by the Board in P.U. 31(2010).

Pension Deferral

The Pension Deferral balance relates to incremental pension costs arising from the Company's 2005 early retirement program. The balance of $11.3 million is being amortized over a ten year period in accordance with P.U.49 (2004). The costs were fully amortized in 2015.

Cost Recovery Deferral

The Cost Recovery Deferral balance relates to the conclusion of the following regulatory amortizations which expired in 2010: 2005 Unbilled Revenue, Municipal Tax Liability, Depreciation, Replacement Energy, Purchased Power Unit Cost Reserve and 2008 GRA Costs. Expiration of these deferrals resulted in a decrease in the 2010 test year revenue requirement of $2,363,000. On August 31, 2010, the Company filed an application for approval to defer the recovery in 2011 of $2,363,000 in costs due to the expirations of the above mentioned deferrals. The Company indicated that the purpose of the application was to allow the Company to earn a just and reasonable return on rate base in 2011, and noted without this deferral its forecast return on rate base for 2011 would be 7.91%, which is below the range (8.05% to 8.41%) approved by the Board in P.U. 46(2009). In P.U. 30 (2010), the Board approved the deferred recovery, until a further Order of the Board, of $2,363,000 in 2011 due to the conclusion in 2010 of the amortizations. As part of this Order, the Board approved the 2011 Cost Recovery Deferral Account, which is to be charged with the amount by which the actual fixed amortizations of regulatory deferrals in 2011 differ from the fixed amortizations of regulatory deferrals included in the Company's 2010 test year. The amount charged to the account shall be adjusted for applicable income taxes. In P.U. 22 (2011), the Board approved the deferred recovery, until a further Order of the Board, of an additional $2,363,000 in 2012 due to the conclusion in 2010 of the amortizations. In P.U. 13 (2013) the Board approved amortization of these cost recovery deferrals over three years. Amortization of this account commenced in 2013.The costs were fully amortized in 2015.

Cost of capital cost recovery deferral

The cost of capital cost recovery deferral account reflects the deferred recovery of $2,487,000 reflecting the difference between the 8.38% return on equity currently in customer electricity rates and the 8.80% return on equity approved in P.U. 17 (2012). In P.U. 13 (2013) the Board approved a three year amortization of the cost of capital recovery deferral. Amortization of this account commenced in 2013. The costs were fully amortized in 2015.

Deferred general rate application costs

In P.U. 13 (2013) the Board approved the deferral of cost related to 2013/2014 GRA as well as amortization of this deferral over a three year period commencing in 2013. Actual costs incurred and deferred were approximately $965,000 with amortization of $321,000 incurred in 2013 and $322,000 in 2014. The costs were fully amortized in 2015.

Conservation and Demand Management Deferral

The Conservation and Demand Management deferral account arose as a result of the Company's implementation of conservation and demand management programs. These costs totaled $1,357,000 (before tax) and the Board ordered pursuant to P.U. 13 (2009) that these costs be deferred until a further Order of the Board. In P.U.43 (2009), the Board approved the Company's proposal to recover the 2009 conservation programming costs over the remaining four years of the five year Energy Conservation Plan through the Conversation Cost Deferral Account. Amortization of this account commenced in 2010.

Pursuant to P.U. 13 (2013) the Board approved the Company's proposed change in definition of conservation program costs and the deferral and amortization of annual conservation program costs over seven years with recovery through the Rate Stabilization Account. The actual costs incurred and deferred at December 31, 2015 were $10,511,000 (before tax) with amortization of $1,053,264 in 2015.

Optional Seasonal Rate Revenue and Cost Recovery Account

The Optional Seasonal Rate Revenue and Cost Recovery Account provides for the deferral of annual costs and revenue effects associated with implementing optional rates and conducting the time of day study in accordance with P.U. 8 (2011). The optional seasonal rate charges a higher price for electricity during the months of December to April and a lower rate for May to November. The Company also initiated a study to evaluate time of day rates over a two-year period. In accordance with P.U. 8 (2011), the Company must file an application with the Board for the disposition to the RSA of any balance in this account. The balance at December 31, 2015 was $69,298. This balance was transferred to the RSA on March 31, 2016 pursuant to the Board's approval in P.U. 10 (2016).

Employee future benefits

On November 10, 2011, the Company submitted an application to the Board requesting approval for the January 1, 2012 adoption of US GAAP for regulatory purposes. On December 15, 2011 pursuant to P.U. 27 (2011) the Board approved the Company's adoption of US GAAP for general regulatory purposes.

Upon transition from Canadian GAAP to U.S. GAAP, there were several one-time adjustments with respect to the accounting for employee future benefits, as follows:

- The unamortized balances for transitional obligations associated with defined benefit pension plans, and the majority of the unamortized transitional obligation for OPEBs were required to be recorded as a reduction to retained earnings. The Board ordered that these balances be recorded as a regulatory asset to be amortized through 2017 as an increase to employee future benefits expense.
- The unamortized balances related to past service costs, actuarial gains or losses, and a portion of the unamortized transitional obligation for OPEBs were required to be recorded as a reduction to equity and classified as accumulated other comprehensive loss on the balance sheet. The Board ordered that these balances be reclassified as a regulatory asset. The amortization of these balances will continue to be included in the calculation of employee future benefit expense.
- The period over which pension expense is recognized differed between Canadian GAAP and U.S. GAAP. Therefore the cumulative difference was recorded as a regulatory asset to be recovered from customers in future rates. The disposition of balances in this account will be determined by a further order of the Board.

In P.U. 27 (2011) the Board ordered that Newfoundland Power *"apply to the Board for approval of changes to existing regulatory assets and liabilities and the creation of any new regulatory assets and liabilities, along with appropriate definitions of the accounts related to these regulatory assets and liabilities, that will be required to effect the adoption of US GAAP".*

On April 9, 2012, the Company submitted an application to the Board requesting specific approval of the following:

i. Opening balances for regulatory assets and liabilities associated with employee future benefits which arise upon Newfoundland Power's adoption of US GAAP effective January 1, 2012 and
ii. a definition of the account related to those regulatory assets and liabilities

The Company's Application included a comparison between the actual opening regulatory assets and liabilities as of January 1, 2012 related to employee future benefits which created a regulatory asset of $131,249,000 (comprising the Defined Benefit Pension Plan regulatory asset of $109,197,000, OPEBs Plan regulatory asset of $21,116,000 and the PUP regulatory asset of $936,000).

In P.U. 11 (2012) the Board approved the creation of a regulatory asset to reflect the accumulated difference to December 31, 2012 in defined benefit pension expense calculated under US GAAP and Canadian Generally Accepted Accounting Principles. In P.U. 13 (2013) the Board approved the recognition of defined pension expense in accordance with U.S GAAP and a regulatory asset of $12,400,000, resulting from P.U. 11 (2012), to be amortized over 15 years commencing in 2013.

As of December 31, 2015 the regulated asset for employee future benefits was $113,044,000.

Deferred income taxes

Deferred income tax assets and liabilities associated with certain temporary timing differences between the tax basis of assets and the liabilities carrying amount are not included in customer rates. These amounts are expected to be recovered from (refunded to) customers through rates when the income taxes actually become payable (recoverable). The Company has recognized this deferred income tax liability with an offsetting increase in regulatory assets. Net regulatory asset for deferred income taxes at December 31, 2015 was $179,532,000.

Weather Normalization Account

The Weather Normalization reserve reduces earnings volatility by adjusting purchased power expense and electricity sales revenue to eliminate variances in purchases and sales caused by the difference between normal and actual weather conditions.

In P.U. 13 (2013) the Board approved the amortization of the December 31, 2011 year-end balance of the weather normalization account of $7,006,000 ($5,020,000 after future income tax) over a three year period beginning in 2013, representing an amortization of approximately $2,335,000 ($1,673,000 after future income tax) each year; 2015 was final year for the amortization. In addition, commencing in 2013, P.U. 13 (2013) also approved the disposition of the balance accrued in the Weather Normalization Account in the previous year to the Rate Stabilization Account at March 31 of the following year. In P.U. 11 (2016) the Board approved the December 31, 2015 net regulatory asset balance in the Weather Normalization Account of $6,212,000 ($4,410,537 net of future income tax).

Future Removal and Site Restoration Provision

The Future Removal and Site Restoration Provision account represents amounts collected in customer electricity rates over the life of certain property, plant, and equipment which are attributable to removal and site restoration costs that are expected to be incurred in the future. The balance is calculated using current depreciation rates. For 2015 the balance in this account was $139,700,000 (2014 - $135,357,000).

Demand Management Incentive Account

The Demand Management Incentive Account, along with the Energy Supply Cost Variance, a component of the Rate Stabilization Clause also approved in P.U. 32 (2007), provides the Company with the ability to recover its costs associated with the variability in purchased power costs inherent in the demand and energy wholesale rates. According to P.U. 21 (2009), the Demand Management Incentive Account establishes: (I) a range of +/- 1% of test year wholesale demand costs for which no account transfer is required; and (ii) the use of the test year unit demand costs as the basis for comparison against actual unit demand costs in determining the purchased power cost variance for comparison to the Demand Management Incentive to determine if an account transfer is required. For 2014, the variation in the account was a regulatory liability of $627,503. This balance was transferred as a credit to the RSA on March 31, 2015 pursuant to the Board's approval in P.U. 8 (2015). The 2015 balance of the Demand Incentive Account was $Nil as there was no supply cost variance outside the Deadband.

Excess earnings

Excess earnings are the earnings that exceed the upper limit of the allowed range of return on rate base of 7.68% approved by the Board in P.U. 51 (2014) for 2015 and 8.06% approved by the Board in P.U. 23 (2013) for 2014. For 2015 and 2014 the Company's regulated earnings did not exceed the upper limit and therefore there is $Nil excess earnings reported on the 2015 Return 13.

In 2013, the Company's regulated earnings exceeded the upper limit of allowed regulated earnings by $68,000 ($49,000 after tax) (see Return on Rate Base and Equity, Capital Structure and Interest Coverage for details).

Based upon our analysis, nothing has come to our attention to indicate that changes in regulatory deferrals for 2015 are unreasonable.

Pension Expense Variance Deferral Account

Scope: Review of calculation of the Pension Expense Variance Deferral Account ("PEVDA") and assess compliance with P.U. 43 (2009)

In P.U. 43 (2009) the Board approved the creation of the Pension Expense Variance Deferral Account. PEVDA was created to capture the difference between the annual pension expense approved for the test year revenue requirement and the actual pension expense computed in accordance with generally accepted accounting principles for any subsequent year. The purpose of the PEVDA is to adjust the variability related to factors outside of the Company's control, primarily due to changes in discount rates. The balance in the PEVDA is a charge or credit to the Rate Stabilization Account as of the 31st day of March in the year in which the difference arises.

The 2015 PEVDA was calculated at $4,935,256. This balance was transferred to the Rate Stabilization Account as a charge on March 31, 2015 in accordance with P.U. 43 (2009).

We confirm that the 2015 PEVDA is calculated in accordance with P.U. 43 (2009).

Other Post-Employment Benefits Cost Variance Deferral Account

Scope: ***Review the calculation of the Other Post-Employment Benefits Cost Variance Deferral Account ("OPEBVDA") and assess compliance with P.U. 31(2010)***

In P.U. 31 (2010) the Board approved the creation of the Other Post-Employment Benefits Cost Variance Deferral Account. OPEBVDA was created to capture the difference between the annual Other Post-Employment Benefits ("OPEBs") expense approved for the test year revenue requirement and the actual OPEBs expense computed in accordance with generally accepted accounting principles for any subsequent year. The purpose of the OPEBVDA is to adjust the variability related to factors outside the Company's control, primarily due to changes in discount rates. The OPEBs expense for the year is the total of (i) the OPEBs expense for regulatory purposes for the year, and (ii) the amortization of OPEBs regulatory asset for the year. The balance in the OPEBVDA is a charge or credit to the Rate Stabilization Account as of the 31st day of March in the year in which the difference arises.

The 2015 OPEBVDA was calculated at $(1,701,520). This balance was transferred to the Rate Stabilization Account as a credit on March 31, 2015 in accordance with P.U. 31 (2010).

We confirm that the 2015 OPEBVDA is calculated in accordance with P.U. 31 (2010).

Optional Seasonal Rate Revenue and Cost Recovery Account

Scope: Review of calculation of the Optional Seasonal Rate Revenue and Cost Recovery Account and assess compliance with P.U. 8 (2011) and P.U. 13 (2013)

In P.U. 8 (2011) and P.U. 10 (2014) the Board approved Rate #1.1S Domestic Seasonal – Optional (the "Optional Seasonal Rate"), with effect from July 1, 2011. The Board also approved the Optional Seasonal Rate Revenue and Cost Recovery Account to provide for the deferral of annual costs and revenue effects associated with implementing the Optional Seasonal Rate and the operating costs associated with a two-year study to evaluate time-of-day rates (the "TOD Rate Study"). On December 31st of each year from 2011 until further order of the Board, this account is to be charged with: (i) the current year revenue impact of making the Domestic Seasonal – Optional Rate available to customers and (ii) the operating costs associated with implementing the Domestic Seasonal – Optional and the Time-of-Day Rate Study. In P.U. 13 (2013) the Board approved to maintain the Optional Seasonal Rate Revenue and Cost Recovery Account until the next general rate application.

In accordance with P.U. 8 (2011), the Company must file an application with the Board no later than the first day of March each year for the disposition to the Rate Stabilization Account of any balance in this account. This application for the disposition of the 2015 balance was filed February 26, 2016, within the deadline.

The Optional Seasonal Rate Revenue and Cost Recovery Account balance at December 31, 2015 was $69,298. This balance was approved to be transferred to the Rate Stabilization Account as a charge as of March 31, 2016 in P.U. 10 (2016).

Nothing has come to our attention to indicate that the Company is not in compliance with P.U. 8 (2011) and P.U. 13 (2013).

Productivity and Operating Improvements

Scope: ***Review the Company's initiatives and efforts with respect to productivity improvements, rationalization of operations and expenditure reductions. Inquire as to the Company's reporting on Key Performance Indicators.***

On an ongoing basis, Newfoundland Power undertakes initiatives aimed at improving reliability of service and efficiency of operations. According to the information provided by Newfoundland Power, the productivity and operational improvements undertaken in 2015 are as follows:

1. Made capital investments of $101 million of which over 49% were targeted directly to replacing or refurbishing deteriorated and defective equipment.

2. Continued Feeder Upgrades under the "Rebuild Distribution Lines Program".

3. Continued work under the Transmission Line Strategy and the Substation Modernization Plan.

4. The Company now has over 66% Automated Meter Reading ("AMR") penetration Island-wide. Newfoundland Power has reduced the number of meter reading estimates in 2015 by over 40% from 2014. AMR technology enables collection of unscheduled meter readings while driving to the scheduled routes. This additional data eliminated approximately 53,000 estimates in 2015.

5. The Company completed updates to its website, launching full self-service options for landlords and property managers. The new features allow landlords to sign-up for a landlord agreement online, manage properties on their existing agreement and track the status of their properties.

6. The Company completed an upgrade to its field work scheduling system. This provided a number of work flow improvements such as allowing crews to create work orders in the field and allowing drawings and pictures to be attached to work orders electronically.

7. Approximately 89,000 or 35% of total billed accounts are now using ebills. Internal promotion via the Contact Centre continues to be a strong driver of growth. A customer contest (Say Yes to Paperless) was conducted again in this quarter. In addition, emails allowing a simple "one-click signup" were forwarded to all customers who had an email address on the Company's system but were not previously receiving ebills.

8. The Company completed an island wide implementation of electronic tailboards and voice recorded job steps for pre-job hazard assessments. Daily hazard assessments for line operations are completed via an electronic tailboard form, including voice recordings detailing the job steps, and are attached to the crews' work orders in the scheduling system. The use of this technology enhances the quality of job safety planning through monitoring, feedback and coaching.

9. The functionality of customer outage alerts was expanded to include planned outage notifications. This allows the Company to make customers aware of planned power interruptions in their neighborhood up to 48 hours in advance of the event. The service also offers updates when the planned interruption changes, and when it actually begins and ends. There are now over 8,000 customers signed up to receive outage alerts via text or email.

10. Centralized dispatch and mobile work management technology were key contributors to field service improvements in 2015. Customer requests for location of underground distribution cables were integrated into the centralized scheduling and dispatching process.

11. In 2015, the Company started a two year project to collect electrical system connectivity information for all customers in preparation for the implementation of a new Outage Management system. Approximately 50% of all customer connectivity data was compiled in the Company's geographic information system ("GIS") in 2015, as planned. Operations staff rely on GIS for electrical system diagrams, customer, work order, outage ticket and vehicle locations, dispatching work and improving communication with customers.

12. Continued the Substation Modernization and Refurbishment program in total 70% of the distribution feeders are now automated.

13. Implemented an Electronic Truck Inspection system to allow drivers to more easily meet legislated inspection requirements.

14. Continued to install down line reclosers to provide for improved control of the distribution system.

Performance Measures

Newfoundland Power notes its performance targets focus on the Company's ability to reasonably control costs, while continuing to improve service reliability, maintain good customer service satisfaction results and a strong safety and environmental record.

The performance targets are established based on historical data, adjusted for anomalies where necessary, and reflect either stable performance or continued improvement over time. Actual results are tracked using various internal systems and processes. They are reported and re-forecasted internally on a monthly basis.

The following table lists the principal performance measures used in the management of the Company:

Category	Measure	Actual 2013	Actual 2014	Actual 2015	Plan 2015	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1]	2.23	2.93	2.36	2.38	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply[1]	1.71	2.44	2.11	1.64	No
	Plant Availability (%)	93.0	94.4	94.9	95.0	No
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	86.0	83.5	86.0	87.0	No
	Call Centre Service Level (% per second)	80/60	80/60	82/60	80/60	Yes
	Trouble Call Responded to Within 2 Hours (%)	85.0	81.0	86.0	85.0	Yes
Safety	All Injury/Illness Frequency Rate	1.1	1.2	0.5	1.3	Yes
Financial	Earnings (millions)[2]	$36.6	$37.3	$38.8	$37.1	Yes
	Gross Operating Cost/Customer[3]	$243	$259	$249	$260	Yes

[1] 2014 reliability statistics above exclude the impact of the January Newfoundland and Labrador Hydro (NLH) system problems. 2013 reliability statistics reported above exclude the impact of the January NLH system problems and the November blizzard in Central and Western.
[2] Excludes $12.8m recovery related to Part VI.I tax in 2013.
[3] Excludes pension, OPEBs and early retirement costs.

The following table compares whether the company measures were achieved during the 2013, 2014, and 2015 years:

Category	Measure	Measure Achieved 2013	Measure Achieved 2014	Measure Achieved 2015
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply	Yes	No	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply	No	No	No
	Plant Availability (%)	No	No	No
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	No	No	No
	Call Centre Service Level (% per second)	Yes	Yes	Yes
	Trouble Call Responded to Within 2 Hours (%)	Yes	No	Yes
Safety	All Injury/Illness Frequency Rate	Yes	Yes	Yes
Financial	Earnings (millions)	Yes	Yes	Yes
	Gross Operating Cost/Customer	Yes	No	Yes