NP 2019-2020 General Rate Application
Information Item - #2
Filed: 2018-10-03 Board Secretary: CB

Grant Thornton
An instinct for growth™

Board of Commissioners of Public Utilities
2016 Annual Financial Review of
Newfoundland Power Inc.

Contents

Restrictions, Qualifications and Independence

Purpose

This report was prepared for the Board of Commissioners of Public Utilities in Newfoundland and Labrador. The purpose of our engagement was to present our observations, findings and recommendations with respect to our 2016 annual financial review of Newfoundland Power Inc.

Restrictions and Limitations

This report is not intended for general circulation or publication nor is it to be reproduced or used for any purpose other than that outlined herein without our prior written permission in each specific instance. Notwithstanding the above, we understand that our report may be disclosed as a part of a public hearing process. We have given the Board our consent to use our report for this purpose.

Our scope of work is as set out in our terms of reference letter, which is referenced throughout this report. The procedures undertaken in the course of our review do not constitute an audit of Newfoundland Power's financial information and consequently, we do not express an opinion on the financial information provided by Newfoundland Power. In preparing this report, we have relied upon information provided by Newfoundland Power.

We acknowledge that the Board is bound by the Freedom of Information and Protection of Privacy Act and agree that the Board may use its sole discretion in any determination of whether and, if so, in what form, this Report may be required to be released under this Act.

We reserve the right, but will be under no obligation, to review and/or revise the contents of this report in light of information which becomes known to us.

Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2016 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 2016 was $1,061,044,000 compared to average rate base for 2015 of $1,019,082,000. The Company's calculation of the return on average rate base for 2016 was 7.31% (2015 - 7.48%). The actual rate of return was within the range approved by the Board (7.03% to 7.39%). 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 2016 was $475,765,000 (2015 - $451,501,000). The Company's actual return on average common equity for the year ended December 31, 2016 was 8.90% (2015 – 8.98%). In Order No. 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 2016 the cost of common equity was 8.50% as per Order No. P.U. 18 (2016). The actual return on average common equity for 2016 was 8.90% 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 13.36% under budget in 2016. The capital expenditures were under the approved budget (including projects carried over from prior years) on a net basis by $5,557,000 (4.24%). However, for each category of expenditure, the variances ranged from an over-budget of 16.63% to an under-budget of 29.77%. Significant variances are explained in our report.

The Company experienced a 3.40% increase in revenue from rates in 2016 as compared to 2015. The increase can be explained by higher customer energy rates.

Net operating expenses in 2016 decreased by $5,356,000 from 2015, which is primarily due to a decrease in Pension and early retirement expenses. This cost 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 2016 are unreasonable.

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 2016 Pension Expense Variance Deferral Account (PEVDA) operated in accordance with Order No. P.U. 43 (2009).

Based on our review, the 2016 Other Post-Employment Benefits Cost Variance Deferral Account (OPEBVDA) operated in accordance with Order No. P.U. 31 (2010).

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 2016 the Company met six out of nine of its planned performance measures. The Company fell short of its targets in the following categories: "Plant Availability", "% of Satisfied Customers as measured by Customer Satisfaction Survey", and "All Injury/Illness Frequency Rate."

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2016 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,
   - Conservation and demand 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 Order No. P.U. 19 (2003) and Order No. P.U. 32 (2007).

5. Examine the Company's 2016 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 Company's 2016/2017 General Rate Application ("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 Order No. 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 Order No. P.U. 31 (2010).

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, 2016 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 7, 2017. 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 30, 2017, the Company filed a revised system of accounts as part of its 2016 Annual Report. In submitting these changes the Company noted that the revisions mainly relate to an account approved by the Board resulting from the 2016 General Rate Application and the elimination of accounts that are no longer required.

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, 2016 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 2016 was $1,061,044,000 which is an increase of $41,962,000 (4.12%) over the average rate base for 2015 of $1,019,082,000. 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 2016; 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 2016, 2016 Test Year and 2015 (all figures shown are averages):

(000)'s	2016	Test Year 2016	2015
Net Plant Investment (average)			
Plant Investment	$1,703,478		$1,629,189
Accumulated Depreciation	(681,742)		(657,233)
CIAC's	(35,166)		(33,970)
	986,570	987,068	937,986
Additions to Rate Base (average)			
Deferred Charges (a)	96,877	96,830	101,448
Cost Recovery Deferral for Seasonal/TOD Rates (b)	25	25	59
Cost Recovery Deferral for Hearing Costs (c)	341	400	161
Cost Recovery Deferral for Regulatory Amortizations (d)	-	-	553
Cost Recovery Deferral – 2012 Cost of Capital (e)	-	-	294
Cost Recovery Deferral – 2013 Revenue Shortfall (f)	-	-	563
Cost Recovery Deferral – Conservation (g)	9,384	8,893	6,200
Customer Finance Programs (h)	1,276	1,174	1,174
Weather Normalization (i)	3,066	2,205	1,386
	110,969	109,527	111,838
Deductions from Rate Base (average)			
Other Post-Employment Benefits (j)	42,646	42,519	35,822
Customer Security Deposits (k)	1,036	993	973
Accrued Pension Obligation (l)	5,120	5,111	4,795
Deferred Income Taxes (m)	1,727	1,794	1,899
Excess Earnings (n)	25	25	49
Demand Management Incentive Account (o)	-	-	223
Cost Recovery Deferral – 2016 Cost Recovery Deferral (p)	723	733	-
	51,277	51,175	43,761
Average Rate Base before Allowances	1,046,262	1,045,420	1,006,063
Rate Base Allowances			
Materials and Supplies	6,464	6,485	6,280
Cash Working Capital	8,318	8,429	6,739
	14,782	14,914	13,019
Average Rate Base	$ 1,061,044	$ 1,060,334	$ 1,019,082

(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 $96,877,000 (2015 - $101,448,000) included in the 2016 rate base consists of average deferred pension costs of $96,802,000 (2015 - $101,384,000) and credit facility costs of $75,000 (2015 - $64,000). The Company has included a schedule of these costs in Return 8.

(b) In Order No. P.U. 8 (2011) the Board approved the Optional Seasonal Rate Revenue and Cost Recovery Account. Pursuant to Order No. 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 2016 average rate base incorporates $25,000 (2015 - $59,000) related to this deferral account.

(c) In Order No. P.U. 18 (2016) the Board approved the creation of a Hearing Cost Deferral Account to recover over 30 months, commencing July 1, 2016, hearing costs related to the 2016/2017 GRA in the amount of $1,200,000. During 2016, the Company deferred $853,000, $347,000 lower than the approved amount, of 2016/2017 GRA hearing costs. Amortization of approximately $171,000 was recorded in 2016, relating to these costs. The 2016 average rate base includes an addition of $341,000 (2015 - $161,000) which represents the unamortized average balance of the original $853,000.

(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 Order No. P.U. 30 (2010). Order No. 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 Order No. 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 were fully amortized as of December 31, 2015.

(e) In Order No. 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 Order No. 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 were fully amortized as of December 31, 2015.

(f) In Order No. 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 were fully amortized as of December 31, 2015.

(g) In Order No. 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 Order No. 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. The actual costs incurred and deferred in 2016 were $7,200,000 ($5,040,000 after tax) resulting in additional annual amortization of $720,000 to commence in 2017. Included in the calculation of the average rate base for 2016 is $9,384,000 (2015 - $6,200,000) 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 2016 average rate base incorporates $1,276,000 (2015 - $1,174,000) related to these programs.

(i) During 2016, the Weather Normalization reserve was impacted by the following:

Transfer to RSA

i. In Order No. 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 $4,411,000 in 2016 (2015 – $33,000 increase).

Other transfers:

i. $102,000 transfer increase (2015 – $108,000 decrease) to the reserve related to the after tax impact of the Degree Day Normalization Reserve Transfer.
ii. $1,823,000 transfer decrease (2015 - $4,303,000 decrease) to the reserve related to the after tax impact of the Hydro Production Equalization Reserve transfer.

The net impact was a net increase to the reserve of $2,690,000 (2015 - $6,051,000 decrease). The ending balance in this reserve account totaled ($1,721,000) compared to a balance of ($4,411,000) at December 31, 2015 (an average of ($3,066,000) for 2016 (2015 – ($1,386,000)).

(j) Other Post-Employment Benefits is equal to the difference, at December 31, 2016, between the OPEBs liability of $77,619,000 and the OPEBs asset of $31,536,000. The calculation of the 2016 average rate base of $42,646,000 is equal to the average of the December 31, 2016 net liability of $46,083,000 and the December 31, 2015 net liability of $39,208,000.

(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 2016 average rate base incorporates $1,036,000 (2015 - $973,000) related to customer security deposits.

(l) The 2016 average rate base calculation incorporates $5,120,000 (2015 - $4,795,000) 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 Order No. 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 Order No. 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 2016 average rate base is ($1,179,000) and ($11,457,000) respectively. The remaining balance of the deferred income tax liability in the amount of $14,363,000 relates to capital assets. This results in an average balance for deferred income tax liability of $1,727,000 (2015 - $1,899,000).

(n) In Order No. 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. The 2016 average rate base incorporates $25,000 (2015 - $49,000) related to this account.

(o) In Order No. 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 Order No. 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 2016 balance of the Demand Incentive Account was $Nil as there was no supply cost variance outside the Deadband. The 2016 average rate base incorporates $Nil (2015 - $223,000) related to this account.

(p) In Order No. P.U. 18 (2016) the board approved the deferral over a 30 month period of a $2,580,000 (before tax) over-recovery of revenue in 2016 due to a July 1, 2016 rate implementation date. During 2016, the Company deferred the after tax amount of ($1,806,000). Amortization of approximately ($361,000) was recorded in 2016, relating to this over-recovery of revenue. The 2016 average rate base includes deduction of $723,000 (2015 - $Nil) which represents the unamortized average balance of the original $1,806,000.

The net change in the Company's average rate base from 2015 to 2016 can be summarized as follows:

(000's)	2016	2015
Average rate base - opening balance	$ 1,019,082	$ 964,930
Change in average deferred charges and deferred regulatory costs	(3,375)	(1,615)
Average change in:		
Plant in service	74,289	82,016
Accumulated depreciation	(24,509)	(22,497)
Contributions in aid of construction	(1,197)	(1,164)
Weather normalization reserve	1,681	4,735
Other post employment benefits	(6,824)	(7,847)
Future income taxes	172	302
Rate base allowances	1,763	996
Other rate base components (net)	(38)	(774)
Average rate base - ending balance	$ 1,061,044	$ 1,019,082

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2016 average rate base, and therefore conclude that the 2016 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 2016 was 7.31% (2015 – 7.48%). 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 2016, the return on average rate base is calculated in accordance with the methodology approved in Order No. 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 2014 to 2016 is set out in the table below.

	2016	2015	2014
Actual Return on Average Rate Base	7.31%	7.48%	7.83%
Upper End of Range set by the Board	7.39%	7.68%	8.06%
Lower End of the Range set by the Board	7.03%	7.32%	7.70%

The Board approved the Company's rate of return on average rate base of 7.21% in a range of 7.03% to 7.39% for 2016 in Order No. P.U. 25 (2016). As noted above, the Company's actual return on average rate base for 2016 was 7.31% which was inside the range set by the Board.

The actual rate of return for 2015 was within the range set by the Board.

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

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 Order No. P.U. 18 (2016) the Board reconfirmed its previous position as per Order No. P.U. 13 (2013) 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 2016 as reported in Return 24 is as follows:

	2016 Average		**2015**	**2014**
	(000's)	**Percent**	Percent	Percent
Debt	**$572,841**	**54.17%**	54.85%	54.85%
Preferred equity	**8,935**	**0.84%**	0.88%	0.92%
Common equity	**475,765**	**44.99%**	44.27%	44.23%
	$1,057,541	**100.00%**	100.00%	100.00%

Pursuant to Order No. 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 2016 test year in Return 26. The embedded cost of debt for 2016 was 6.27% which represents a 23 bps decrease from 2015 embedded cost of debt of 6.50%.

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 Order No. P.U. 18 (2016).

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, 2016 is included on Return 27 of the annual report to the Board. The average common equity for 2015 was $475,765,000 (2015 - $451,501,000). The Company's actual return on average common equity for 2016 was 8.90% (2015 – 8.98%).

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 Order No. P.U. 40 (2005), including the deemed capital structure per Order No. P.U. 19 (2003), Order No. P.U. 32 (2007), Order No. P.U. 43(2009), Order No. P.U. 13 (2013), and Order No. P.U. 18 (2016).
- recalculated the rate of return on common equity for 2015 and ensured it was in accordance with established practice, Order No. P.U. 32 (2007), and Order No. P.U. 18 (2016).

In Order No. 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 2016 the cost of common equity was 8.50% as per Order No. P.U. 18 (2016). The actual return on average common equity for 2016 was 8.90% 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)	**2016**	2015	2014
Net income	**$40,508**	$ 39,314	$ 37,840
Income taxes	**11,851**	10,925	10,795
Interest on long term debt	**34,846**	35,020	36,327
Interest during construction	**(1,304)**	(1,240)	(1,435)
Other interest and amortization of debt discount costs	**1,090**	1,361	880
Total	**$86,991**	$ 85,380	$ 84,407
Interest on long term debt	**$34,846**	$35,020	$36,327
Other interest and amortization of debt discount costs	**1,090**	1,361	880
Total	**$35,936**	$36,381	$37,207
Interest Coverage (times)	**2.4**	2.3	2.3

The above table shows that the interest coverage increased by 0.1 times from 2015 to 2016.

In Order No. 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 2016 is 2.4 times.

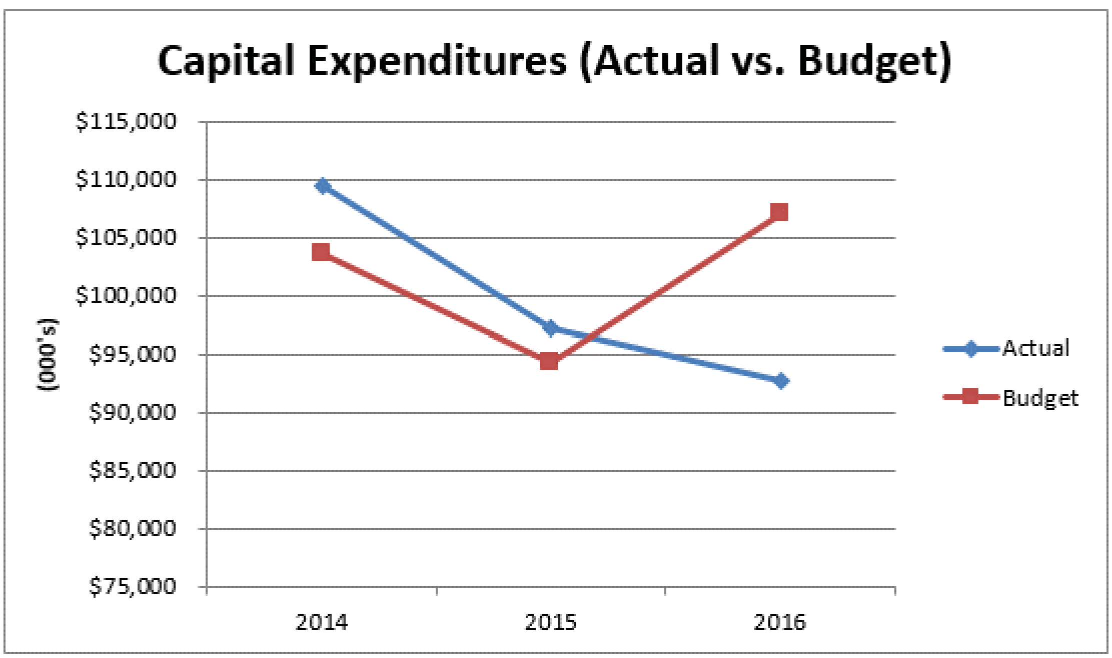
Capital Expenditures

Scope: ***Review the Company's 2016 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 2014 to 2016:

($000's)	2014	2015	2016	Notes
Actual	$ 109,429	$ 97,155	$ 92,727	1
Budget	$ 103,572	$ 94,211	$ 107,028	
Over (under) budget	5.66%	3.12%	(13.36%)	

Note 1: Total expenditures per the 2016 Capital Budget report includes the carryover amount of $7,284,000 for a total of $100,011,000. The carryover amount is made up of seven projects included in the following categories: $637,000 to generation - hydro; $1,064,000 to substations; $898,000 to transmission; $2,574,000 to distribution; $1,024,000 to Transportation; $150,000 to Telecommunications, and $937,000 to information systems. According to the Company, these expenditures will occur in 2017.



The following table provides a summary of the capital expenditure activity in 2016 as reported in the Company's *"2016 Capital Expenditure Report"*:

($000's)	Capital Budget			Actual Expenditures		
	Prior Years	2016 (1)	Total	Prior Years	2016	Total
2016 Capital Projects	$ -	$ 88,450	$ 88,450	$ -	$ 74,564	$ 74,564
2015 Projects Carried to 2016 & Multi Year Projects						
Facility Rehabilitation - 2015	1,586	-	1,586	1,365	14	1,379
Substation Refurbishment and Modernization - 2015 (2)	9,961	-	9,961	10,777	233	11,010
Rebuild Transmission Lines - 2015 (3)	5,731	-	5,731	5,731	759	6,490
Trunk Feeders - 2015 (4)	991	-	991	683	72	755
Pierre's Brook Plan Refurbishment - Multi Year	750	15,012	15,762	639	14,154	14,793
Company Building Renovations - Duffy Place - Multi Year (5)	2,068	724	2,792	1,049	2,562	3,611
SCADA System Replacement - Multi Year	2,833	2,842	5,675	1,620	3,715	5,335
	23,920	18,578	42,498	21,864	21,509	43,373
Grand Total	**$ 23,920**	**$ 107,028**	**$ 130,948**	**$ 21,864**	**96,073 (6)**	**$ 117,937**

(1) Approved by Order No. P.U. 28 (2015).
(2) The Company has noted that the unfavorable budget variance was related to the price of major equipment purchases and installation contract pricing obtained through competitive tendering, being higher then budget estimates.
(3) The Company has noted that the unfavorable variance was associated with the 400L rebuild project in the Stephenville Area. Additional expenses were incurred on the project due to the environmental conditions encountered on the right of way. The construction of corduroy roads to access the site were required because a large section of the work was located in a very wet and boggy area. Additionally, an extra expenditure was incurred to upgrade an access from the Trans-Canada Highway to meet Department of Transportation specifications.
(4) The Company has noted that the budget variance primarily resulted from delays in proceeding with planned underground vault upgrades due to easement acquisition difficulties and the need to coordinate the required outages with the downtown St. John's business community. The work is now planned to be addressed in 2017.
(5) The Company has noted that the budget variance is primarily related to more work being required to upgrade the HVAC system than anticipated, and pricing obtained through a competitive tender also being higher than expected.
(6) Represents $92,727,000 and $3,346,000 in actual expenditures relating to 2016 and 2015 capital projects, respectively.

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

($000's)	2016 Budget (1)	2016 Actuals (2)	Variance	Carryover (3)	Variance Including Carryover	%
Generation - Hydro	$ 19,693	$ 17,983	$ (1,710)	$ 807	$ (903)	(4.59%)
Generation - Thermal	1,738	1,515	(223)	-	(223)	(12.83%)
Substation	27,901	24,498	(3,403)	1,064	(2,339)	(8.38%)
Transmission	11,798	10,536	(1,262)	898	(364)	(3.09%)
Distribution	46,046	42,577	(3,469)	2,574	(895)	(1.94%)
General property	3,908	4,558	650		650	16.63%
Transportation	3,258	2,353	(905)	1,024	119	3.65%
Telecommunications	514	211	(303)	150	(153)	(29.77%)
Information systems	10,842	9,743	(1,099)	937	(162)	(1.49%)
Unforeseen	750	-	(750)	-	(750)	(100.00%)
General expenses capitalized	4,500	3,963	(537)	-	(537)	(11.93%)
Total	**$ 130,948**	**$ 117,937**	**$ (13,011)**	**$ 7,454**	**$ (5,557)**	**(4.24%)**

1 - Includes prior years projects and current year budgeted amounts as there were projects incomplete at the previous year ends.
2 - 2016 actuals include the total expense for projects carried forward from 2015.
3 - Represents $7,284,000 included in the 2016 budget and an amount of $170,000 from a 2015 project, but not yet spent.

As indicated in the table, capital expenditures were less than the approved budget (including projects carried over from prior years) on a net basis by $13,011,000 and by $5,557,000 (4.24%) when carryover amounts are taken into account. However, for each category of expenditure, the variances ranged from an over-budget of 16.63% for the General property category to an under-budget of 29.77% 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	437
Public Safety Around Dams	200
Substation Refurbishment and Modernization	1,064
Transmission Line Rebuild	898
Trunk Feeders	177
Distribution Reliability Initiative	750
Distribution Feeder Automation	203
St. John's Main Underground Refurbishment	1,444
Purchase of Vehicles and Aerial Devices	1,024
Fibre Optic Network	150
Application Enhancements	154
System Upgrades	420
Outage Management System Replacement	87
SCADA System Replacement	276
Facility Rehabilitation - 2015	170
Total Carryover	**$ 7,454**

The Company has provided detailed explanations on budget to actual variances in its "2016 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 2016 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 3.12% in 2015 and -13.36% in 2016 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

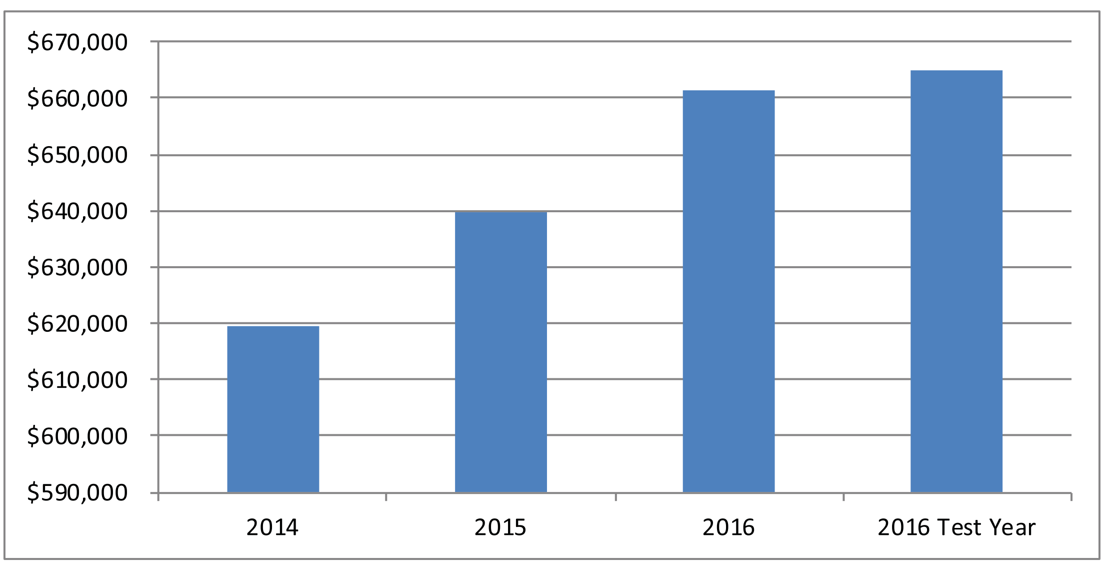
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2016 calendar year.

Revenue

Scope: Review the Company's 2016 revenue in comparison to prior years and follow up on any significant variances.

We have compared the actual revenues for 2014 to 2016 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

($000's)	2014	2015	2016	2016 Test Year
Residential	$ 390,614	$ 403,910	$ 420,159	$ 422,171
General Service				
0-100 kW	82,080	85,093	88,362	88,976
110-1000 kVA	88,789	93,725	96,404	97,267
Over 1000 kVA	39,743	38,400	38,021	37,889
Streetlighting	15,262	15,541	15,928	15,918
Discounts forfeited	3,016	2,962	2,507	2,894
Revenue from rates	$ 619,504	$ 639,631	$ 661,381	$ 665,115
Year over year percentage change	5.57%	3.25%	3.40%	



The above graph demonstrates that the Company has seen a 3.40% increase in revenue from rates in 2016 as compared to 2015. The increase primarily relates to an increase in customer energy rates effective July 1, 2015 and July 1, 2016 related to Order No. P.U. 17 (2015) and Order No. P.U. 18 (2016) respectively. For residential sales there was an increase of 4.02% in 2016 revenue from 2015. GWh sold in this category increased by 0.04%, and the number of residential customers increased by 1.04%.

The comparison by rate class of 2016 actual revenues to 2016 test year is as follows:

($000's)	2015	2016	2016 Test Year	Actual - TY Variance	%
Residential	$ 403,910	$ 420,159	$ 422,171	$ (2,012)	(0.48%)
General Service					
0-100 kW	85,093	88,362	88,974	(612)	(0.69%)
110-1000 kVA	93,725	96,404	97,266	(862)	(0.89%)
Over 1000 kVA	38,400	38,021	37,887	134	0.35%
Streetlighting	15,541	15,928	15,919	9	0.06%
Discounts forfeited	2,962	2,507	2,894	(387)	(13.37%)
Total revenue from rates	$ 639,631	$ 661,381	$ 665,111	$ (3,730)	(0.56%)

We have also compared the 2016 budget energy sales in GWh to the actual sold in 2016:

	2015	2016	2016 Test Year	Actual – TY Variance	%
Residential	3,654.2	3,655.6	3,676.6	(21.0)	(0.57%)
General Service					
0-100 kW	792.4	797.7	805.0	(7.3)	(0.91%)
110-1000 kVA	998.3	1,010.4	1,019.3	(8.9)	(0.87%)
Over 1000 kVA	479.5	453.8	457.1	(3.3)	(0.72%)
Streetlighting	32.2	32.6	32.5	0.1	0.31%
Total	5,956.6	5,950.1	5,990.5	(40.4)	(0.67%)

Actual 2016 revenue from rates was lower than 2016 test year with an overall decrease in actual sales of $3,730,000 (0.56%) from the 2016 test year. There was a 0.67% decrease in GWh sold in 2016 compared to 2016 test year. The largest variances in revenue can be seen in the Residential and 110-1000 KVA class where revenues decreased by $2,012,000 (0.48%) and $862,000 (0.89%) respectively.

Operating and General Expenses

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

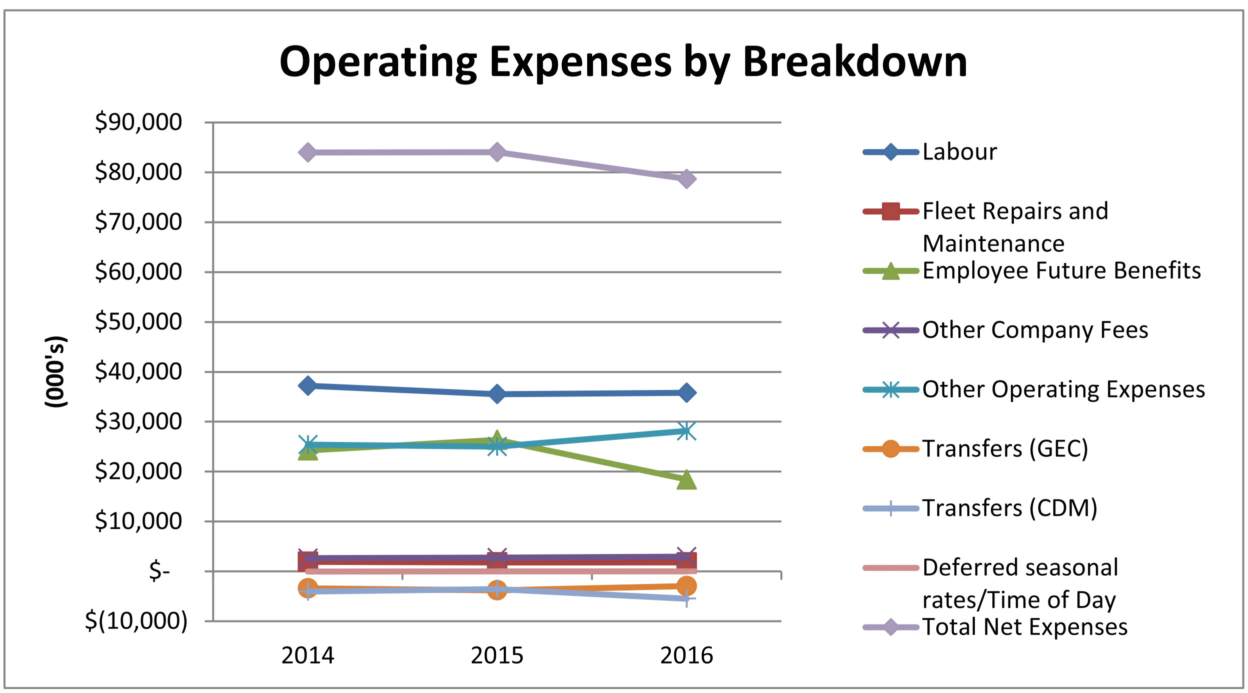
(000's)	Actual 2016	Test Year 2016	Actual 2015	Actual 2014	Variance Actual-Test	Variance 2016-2015
Labour	$ 36,770		$ 36,485	$ 37,871		$ 285
Reclass OPEB labour cost	(981)		(969)	(658)		(12)
Total Labour	35,789	36,898	35,516	37,213	(1,109)	273
Vehicle expense	1,797	1,698	1,786	1,901	99	11
Operating materials	1,425	1,641	1,583	1,857	(216)	(158)
Inter-company charges	2,145	2,197	1,560	1,710	(52)	585
Plants, Subs, System Oper & Bldgs	2,770	2,269	2,367	2,312	501	403
Travel	1,160	1,237	1,052	1,318	(77)	108
Tools and clothing allowance	1,161	1,133	1,130	1,192	28	31
Miscellaneous	1,821	1,954	1,765	1,970	(133)	56
Conservation	4,253	2,280	2,466	1,762	1,973	1,787
Taxes and assessments	1,214	1,150	1,123	1,040	64	91
Uncollectible bills	1,194	1,310	1,313	1,490	(116)	(119)
Insurance	1,293	1,241	1,260	1,243	52	33
Severance & other employee costs	47	73	72	58	(26)	(25)
Education, training, employee fees	275	356	298	310	(81)	(23)
Trustee and directors' fees	471	467	462	431	4	9
Other company fees	2,944	3,354	2,757	2,650	(410)	187
Stationary & copying	266	279	230	266	(13)	36
Equipment rental/maintenance	838	803	746	769	35	92
Communications	2,959	3,139	3,184	3,220	(180)	(225)
Advertising	1,519	1,687	1,251	1,444	(168)	268
Vegetation management	1,820	1,827	1,766	1,789	(7)	54
Computing equipment & software	1,359	1,336	1,058	915	23	301
Total Other	32,731	31,431	29,229	29,647	1,300	3,502
Pension & early retirement program	9,763	9,864	17,702	13,276	(101)	(7,939)
OPEB's	8,678	8,702	8,653	10,968	(24)	25
Total employee future benefits	18,441	18,566	26,355	24,244	(125)	(7,914)
Total gross expenses	86,961	86,895	91,100	91,104	66	(4,139)
Transfers (GEC)	(2,955)	(3,135)	(3,809)	(3,399)	180	854
CDM amortization	1,712	1,713	1,053	420	(1)	659
Deferred CDM program costs	(7,200)	(5,742)	(4,611)	(4,436)	(1,458)	(2,589)
Deferred seasonal rates/TOD	-	-	(9)	(39)	-	9
Deferred regulatory costs	172	200	322	322	(28)	(150)
Total net expenses	$ 78,690	$ 79,931	$ 84,046	$ 83,972	$ (1,241)	$ (5,356)

The above table provides details of operating and general expenses (including non-regulated expenses) by "breakdown" for 2014, 2015, 2016 Test Year and 2016 Actual.

Overall, net operating expenses decreased by 5,356,000 from 2015 to 2016. 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 2016 are unreasonable. The most significant variances between 2016 Test Year and actual are labour and conservation costs. According to the Company, the labour decrease in actual compared to test year is primarily due to a reduction in FTEs reflecting timing of retirements and leaves, timing of implementation of the customer energy conservation program following the approval of the 2016/2017 GRA and advance in meter reading technology. The conservation cost increase in actual compared to test year is due to increased customer uptake on instant rebates for items offering energy savings such as LED light bulbs; the increase in conservation cost is offset by costs deferred to the CDM program deferral account.

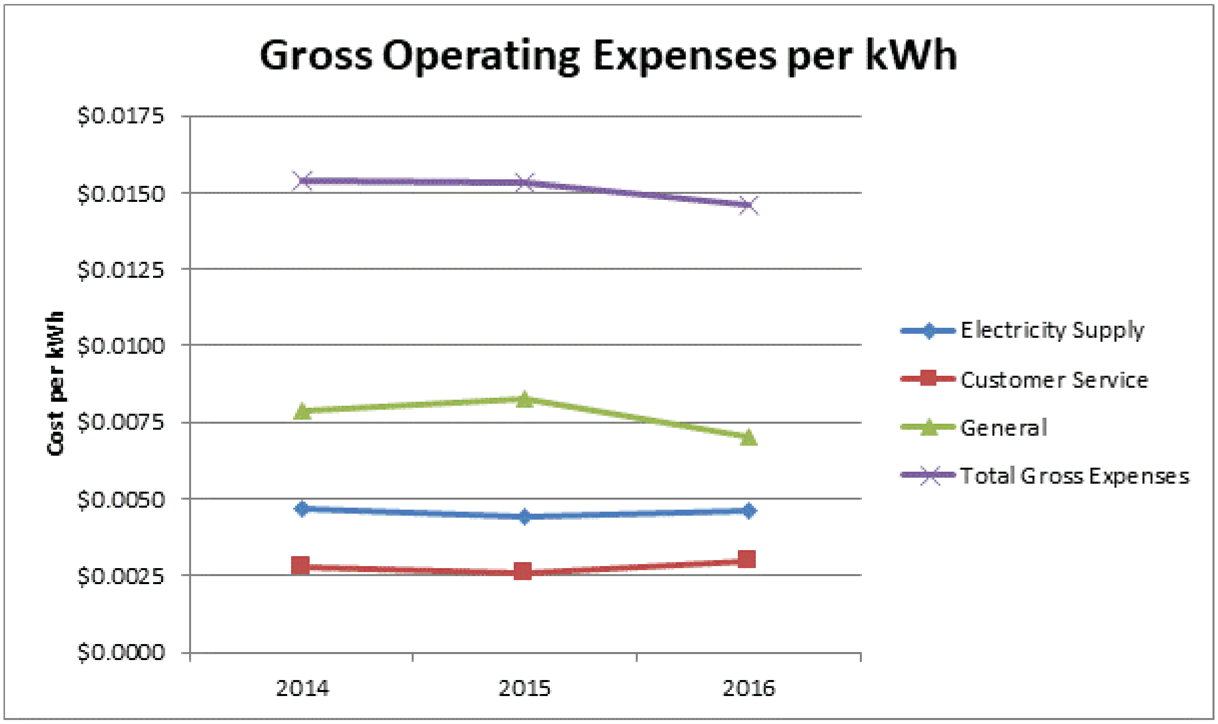
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph shows the trend in operating expenses by breakdown for the period 2014 to 2016.

	Actual		
(000's)	**2014**	**2015**	**2016**
Labour	$ 37,213	$ 35,516	$ 35,789
Fleet Repairs and Maintenance	1,901	1,786	1,797
Employee Future Benefits	24,244	26,355	18,441
Other Company Fees	2,650	2,757	2,944
Other Operating Expenses	25,418	25,008	28,162
Transfers (GEC)	(3,399)	(3,809)	(2,955)
Transfers (CDM)+CDM Amortization	(4,016)	(3,558)	(5,488)
Deferred seasonal rates/Time of Day	(39)	(9)	-
Total Net Expenses	$ 83,972	$ 84,046	$ 78,690



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2014 to 2016 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
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
2016	5,950,100	$ 27,400	$ 0.0046	$ 17,663	$ 0.0030	$ 41,613	$ 0.0070	$ 86,961	$ 0.0146



The table and graph show that total gross expenses per kWh have decreased by approximately 4.6% compared to 2015.

There was a decrease in General Costs of $7.8 million which were partially offset by an increase in Electricity Supply Costs and Customer Service Costs of $1.2 million and $2.2 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 2014 to 2016 (including 2016 plan) is as follows:

	Actual 2016	Plan 2016	Actual 2015	Actual 2014	Actual - Plan	Actual 2016-2015
Executive Group	**6.0**	**6.0**	6.0	5.8	0.0	-
Corporate Office	**20.7**	**21.6**	20.7	22.3	(0.9)	-
Finance	**89.5**	**95.0**	93.5	90.9	(5.5)	(4.0)
Egineering and Operations	**406.9**	**425.0**	418.5	424.4	(18.1)	(11.6)
Customer Relations	**62.8**	**72.7**	68.0	72.9	(9.9)	(5.2)
	585.9	**620.3**	606.7	616.3	(34.4)	(20.8)
Temporary employees	**48.6**	**36.8**	46.3	48.5	11.8	2.3
Total	**634.5**	**657.1**	653.0	664.8	(22.6)	(18.5)

The overall number of FTE's in 2016 compared to 2015 decreased by 18.5. The budgeted number of FTE's in the 2016 Plan was 657.1 versus actual of 634.5. According to the Company, the variances between 2016, 2016 Plan and 2015 are the result of the following:

- Finance is lower than plan and 2015 due primarily to timing of replacement of personnel.
- Engineering and operations is lower than plan and 2015 primarily due to the timing of replacement of personnel for retirements and leaves, as well as labour efficiencies.
- Customer Relations is lower than plan and 2015 primarily due to a shift in Customer Service Representatives from regular to temporary employees and a reduction in Meter Readers resulting from advances in meter reading technology. The decrease is partially offset by the shift of personnel from Corporate Office.
- Temporary Employees is higher than plan and 2015 because of a shift in Customer Service Representatives from regular to temporary employees.

An analysis of salaries and wages by type of labour and by function from 2014 to 2016 is as follows:

(000's)	**Actual 2016**	Actual 2015	Actual 2014	**Variance 2016-2015**
Type				
Internal labour	**$ 63,608**	$ 63,330	$ 62,275	$ 278
Overtime	**4,925**	5,117	6,968	(192)
	68,533	68,447	69,243	86
Contractors	**10,593**	15,232	18,286	(4,639)
	$ 79,126	$ 83,679	$ 87,529	$ (4,553)
Function				
Operating	**$ 36,770**	$ 36,485	$ 37,871	285
Capital and miscellane	**42,356**	47,194	49,658	(4,838)
Total	**$ 79,126**	$ 83,679	$ 87,529	$ (4,553)
Year over year percen	-5.44%	-4.40%	11.32%	

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 2016 were $4,553,000 (-5.44%) lower than 2015.

Internal labour costs in 2016 were higher than 2015 primarily due to normal labour inflation offset by a reduction in full time equivalents reflecting timing of replacement of personnel and labour efficiencies including advances in meter reading technology.

Overtime in 2016 was lower than 2015 because 2015 included increased labour for substation work.

Contract labour for 2016 was lower than 2015 because 2015 included increased contract labour for distribution work such as extensions as well as increased transmission line work.

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 2014 to 2016 are included in the table below:

Salary Cost Per FTE

	Actual 2016	Actual 2015	Actual 2014	Variance 2016-2015
Total reported internal labour costs	**$ 63,608**	$ 63,330	$ 62,275	$ 278
Benefit costs (net)	**(8,470)**	(7,559)	(7,448)	(911)
Other adjustments	**(772)**	(605)	(646)	(167)
Base salary costs	**54,366**	55,166	54,181	(800)
Less: executive compensation	**(1,864)**	(1,750)	(1,932)	(114)
Base salary costs (excluding executive)	**$ 52,502**	$ 53,416	$ 52,249	$ (914)
FTE's (including executive members)	**634.5**	653.0	664.8	
FTE's (excluding executive members)	**630.5**	649.0	661.0	
Average salary per FTE	**85,683**	84,481	81,500	
% increase	**1.42%**	3.66%	3.36%	
Average salary per FTE (excluding executive members)	**83,270**	82,305	79,045	
% increase	**1.17%**	4.12%	3.42%	

The above analysis indicates that the increase in average salary per FTE has decreased in 2016 as compared to 2015 and 2014.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2014 to 2016 and the targets set for 2016:

Measure	Target 2016	Actual 2016	Actual 2015	Actual 2014
Controllable Operating Costs/Customer	**$226.10**	$219.70	$219.80	$223.90
Earnings	**38.3m**	40.0m	38.8m	37.3m
Reliability - Duration of Outages (SAIDI)	**2.36**	2.24	2.36	2.44
Customer Satisfaction - % Satisfied	**86.1%**	86.1%	86.1%	83.5%
Injury Frequency Rate	**0.4**	0.4	0.18	0.51
Regulatory Performance	**Subjective**	140%	140%	150%

2016 STI results were adjusted to remove the impact of severe weather conditions in December. The Company indicated that Regulatory Performance is evaluated on a subjective basis as it is difficult to apply statistical or cost based analyses.

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 2016 is established as a percentage of base pay for the three employee groups. For 2016, all measures relating to 'controllable operating costs/customer', 'earnings', 'SAIDI', 'customer satisfaction', 'safety', and 'regulatory performance' metrics were met.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2014 to 2016:

	Target 2016	**Actual 2016**	**Target 2015**	**Actual 2015**	**Target 2014**	**Actual 2014**
President	50%	67.20%	50%	64.90%	40-50%	64%
Executive	40%	53.90%	40%	51.90%	35%	44.8%
Directors	15%	19.60%	15%	19.60%	15%	19.2%

STI actual payout rates for 'President', 'Executive' and 'Director' employee groups are higher than or equal to the prior year and each payout rate exceeded target consistent with 2015 and 2014.

In dollar terms, the STI payouts for 2014 to 2016 are as follows:

	Actual 2016	**Actual 2015**	**Actual 2014**	**Variance 2016-2015**
President	**$ 242,000**	$ 227,000	$ 360,000	$ 15,000
Executive	**442,000**	401,000	312,000	41,000
Directors	**323,300**	342,200	320,300	- 18,900
Total	**$ 1,007,300**	$ 970,200	$ 992,300	$ 37,100
Year over Year % change	3.82%	-2.23%	-0.77%	

In accordance with Order No. P.U. 19 (2003) the Company has classified STI payouts in excess of 100% of target as a non-regulated expense. In accordance with Order No. P.U. 18 (2016) the Company has also classified STI payouts relating to half of the earnings and regulatory performance metrics as a non- regulated expense. In 2016, the non-regulated portion (before tax adjustment) was $367,818 (2015 - $224,170).

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2014 to 2016.

	Base Salary	Short Term Incentive	Other	Total
2016				
Total executive group	$ 1,180,144	$ 684,000	$ 226,663	$ 2,090,807
Average per executive (4)	**$ 295,036**	**$ 171,000**	**$ 56,666**	**$ 522,702**
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**
% Average increase 2016 vs 2015	5.18%	8.92%	113.34%	12.64%

In addition to general salary increases, base salary for the executive group in 2016 increased from 2015 due to the Vice President of Finance/Chief Financial Officer (CFO) being appointed Chief Operating Officer effective July 1, 2016, in addition to responsibilities as CFO. Other compensation for the executive group in 2016 increased from 2015, primarily due to a performance share unit payout received by each of the executive that was not received in prior years. Base salaries, performance share unit payouts and STI payouts were agreed to the Board of Directors' minutes.

Company Pension Plan

For 2016, we reviewed the accounts supporting the gross charge of $9,763,000 of pension expense for the Company. A detailed comparison of the components of pension expense for 2014 to 2016, and 2016 test year:

	Actual 2016	Test Year 2016	Actual 2015	Actual 2014	Variance 2016-2015
Pension expense per actuary	**$ 7,330,000**	**$ 7,305,000**	$ 15,332,000	$ 11,084,000	$ (8,002,000)
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**557,000**	**547,000**	562,000	568,000	(5,000)
Group RRSP @ 1.5%	**350,000**	**365,000**	384,000	422,000	(34,000)
Individual RRSP's	**1,531,000**	**1,657,000**	1,421,000	1,211,000	110,000
Less: Refunds (net of other expenses)	**(5,000)**	**(10,000)**	3,000	(9,000)	(8,000)
Total	**$ 9,763,000**	**$ 9,864,000**	$ 17,702,000	$ 13,276,000	$ (7,939,000)
Year over year percentage change	**(44.85%)**		33.34%	(9.96%)	

Overall, pension expense for 2016 is lower than 2015 primarily due to a higher discount rate at December 31, 2015, which is used to determine the pension obligation for 2016, as well as a higher expected service life of active members.

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 Order No. 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 0.89% in 2016.

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 7.74% 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 $76,000 in overall RRSP contributions (Group and Individuals) made by the employer in comparison to 2015 primarily reflects wage increases and new hires in the year, which was partially offset by retirements and terminations (28 retirements in 2016). The net increase for RRSP expenditures in 2016 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 Order No. 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 2014 to 2016 and 2016 test year are as follows:

(000's)	Actual 2016	Test Year 2016	Actual 2015	Actual 2014	Variance 2016-2015
Accrued OPEBs	**$ 6,089**	**$ 4,661**	$ 6,055	$ 8,038	$ 34
Amortization of transitional balance	**3,504**	**4,932**	3,504	3,504	-
Amount capitalized	**(915)**	**(891)**	(906)	(574)	(9)
Total	**$ 8,678**	**$ 8,702**	$ 8,653	$ 10,968	$ 25

The 2016 OPEBs expense is relatively consistent with the 2015 OPEBs expense.

Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with Order No. P.U. 19 (2003), Order No. P.U. 32 (2007), Order No. P.U. 43 (2009), and Order No. P.U. 13 (2013);
- compared intercompany charges for the years 2014 to 2016 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2016 and investigated any unusual items;
- vouched a sample of transactions for 2016 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 2014 to 2016 for charges to and from Newfoundland Power Inc.:

	Actual 2016	**Actual 2015**	**Actual 2014**	**Variance 2016-2015**
Charges from related companies				
Regulated	**$ 153,602**	$ 208,781	$ 311,536	$ (55,179)
Non-Regulated	**2,293,715**	1,672,009	1,990,723	621,706
Total	**$ 2,447,317**	$ 1,880,790	$ 2,302,259	$ 566,527
Charges to related companies	**$ 329,339**	$ 229,125	$ 336,758	$ 100,214

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 2016.

- Fortis Inc. estimated its net pool of operating expenses for 2016 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 based upon 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 actual weighted asset basis assets in this calculation.

During the fourth quarter of 2016, a "true up" calculation was completed to reflect actual recoverable expenses which were determined to be $2,145,000 and are summarized as follows:

2016 Recoverable Expenses from Fortis Inc.

	Amount	
Staffing and Staffing Related	$1,293,000	Non-regulated
Director Fees	184,000	Non-regulated
Consulting and Legal fees	142,000	Non-regulated
Trustee Agent Fees	33,000	Regulated
Audit and Other Fees	43,000	Non-regulated
Public Reporting Costs	43,000	Non-regulated
Annual Meeting Expenses	76,000	Non-regulated
Travel (Board and Other)	47,000	Non-regulated
Insurance (D&O)	45,000	Non-regulated
Other Costs	239,000	Non-regulated
	2,145,000	
Less amounts previously billed:		
Q1 2016	512,000	
Q2 2016	542,000	
Q3 2016	542,000	
Q4 2016 balance owing	$ 549,000	

For 2016, Newfoundland Power's percentage allocation of Fortis Inc. corporate costs was 4.95%, down from 5.65% in 2014.

As detailed above, trustee agent fees for $33,000 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 2014 to 2016 with Fortis Inc.:

Intercompany Transactions

(Regulated)	Actual 2016	Actual 2015	Actual 2014	Variance 2016-2015
Charges from Fortis Inc.				
Trustee fees and share plan costs	**$ 33,000**	$ 35,000	$ 48,000	$ (2,000)
Miscellaneous	**53,059**	24,472	128,593	28,587
Staff Charges	**-**	19,756	-	(19,756)
	$ 86,059	$ 79,228	$ 176,593	$ 6,831
Year over year percentage change	**8.62%**	(55.14%)	162.85%	
Charges to Fortis Inc.				
Printing and stationery	**$ -**	$ 2,191	$ 76	$ (2,191)
Postage and couriers	**7,583**	19,468	25,704	(11,885)
Staff charges	**38,282**	44,430	43,667	(6,148)
Staff charges - insurance	**550**	4,639	38,527	(4,089)
Pole removal and installation	**138**	-	769	138
Miscellaneous	**16,895**	7,855	64,713	9,040
	$ 63,448	$ 78,583	$ 173,456	$ (15,135)
Year over year percentage change	**(19.26%)**	(54.70%)	(44.54%)	

The most significant fluctuations from our analysis of regulated charges from Fortis Inc. is an increase in the miscellaneous account of $28,587 and a decrease in the staff charges account of $19,756. This is primarily due to the transfer of pension plan payments for a Fortis employee who transferred to Newfoundland Power, but remained in the Fortis pension plan. These payments were recorded as "miscellaneous" in 2016 and as "staff charges" in 2015.

The most significant fluctuation from our analysis of regulated charges to Fortis Inc. is an $11,885 decreases in postage and couriers. This is primarily a result of a decrease in the amount of mail processed for Fortis Inc.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2014 to 2016:

(Non-Regulated)	**Actual 2016**	**Actual 2015**	**Actual 2014**	**Variance 2016-2015**
Charges from Fortis Inc.				
Director's fees and travel	**231,000**	166,000	373,000	$ 65,000
Annual and quarterly reports	**43,000**	73,000	98,000	$ (30,000)
Staff charges	**1,293,000**	944,000	849,000	$ 349,000
Miscellaneous	**726,715**	489,009	663,602	$ 237,706
	$ 2,293,715	$ 1,672,009	$ 1,983,602	$ 621,706
Year over year percentage change	**37.18%**	(15.71%)	35.20%	

Staff charges increased by $349,000 primarily due to an increase in staff in the investor relations, human resources, planning and forecasting, and information technology functions during the second half of 2015, reflecting a full year impact in 2016. In addition, there was higher share-based compensation due to share price appreciation in 2016.

Miscellaneous charges increased by $237,706, primarily due to an increase in consultant and legal fees from 2015 to 2016 and a Performance Share Unit payout for a former CEO, who retired mid-year 2014 and joined the Fortis Inc. executive team, in the amount of $44,578.

The following table provides a summary and comparison of the other intercompany transactions for 2014 to 2016:

Intercompany Transactions (Other)	Actual 2016	Actual 2015	Actual 2014	Variance 2016-2015
Charges to Fortis Properties				
Staff charges	**$ -**	$ 23,569	$ 12,108	$ (23,569)
Staff charges - insurance	**2,950**	21,796	23,753	(18,846)
Stationary costs	**-**	-	288	-
Miscellaneous	**-**	500	790	(500)
	$ 2,950	$ 45,865	$ 36,939	$ (42,915)
Charges from Fortis Properties				
Hotel/Banquet facilities & meals	**$ -**	$ 3,113	$ 34,048	$ (3,113)
Miscellaneous	-	48,885	1,664	(48,885)
	$ -	$ 51,998	$ 35,712	$ (51,998)
Charges to Fortis Ontario Inc.				
Staff charges	**$ 22,698**	$ 3,620	$ 3,116	$ 19,078
Staff charges - insurance	**$ 1,794**	$ 5,666	$ 4,986	$ (3,872)
IS charges	**-**	4,065	4,208	(4,065)
Miscellaneous	**400**	390	380	10.00
	$ 24,892	$ 13,741	$ 12,690	$ 11,151
Charges to Maritime Electric				
Staff charges	**$ 34,749**	$ 6,541	$ 3,813	$ 28,208
Staff charges - insurance	**756**	934	1,444	(178)
IS charges	**-**	3,048	2,945	(3,048)
Miscellaneous	**530**	530	510	-
	$ 36,035	$ 11,053	$ 8,712	$ 24,982
Charges from Maritime Electric				
Staff charges	**$ -**	$ -	$ 34,372	$ -
Miscellaneous	**2,880**	250	-	2,630
	$ 2,880	$ 250	$ 34,372	$ 2,630
Charges from Central Hudson Gas & Electric				
Miscellaneous	**$ 3,538**	$ 182	$ 13,973	$ 3,356

Intercompany Transactions (Other) Cont'd.	Actual 2016	Actual 2015	Actual 2014	Variance 2016-2015
Charges to Belize Electric Company Ltd.				
Staff charges	**$ 121,021**	$ 20,779	$ -	$ 100,242
Staff charges - insurance	**-**	-	648	-
Miscellaneous	**1,793**	-	-	1,793
	$ 122,814	$ 20,779	$ 648	$ 102,035
Charges to FortisAlberta Inc.				
Staff charges - insurance	**$ -**	$ 39	$ 76	$ (39)
Miscellaneous	**4,510**	4,260	13,280	250
	$ 4,510	$ 4,299	$ 13,356	$ 211
Charges from FortisAlberta Inc.				
Miscellaneous	**$ 44,744**	$ 49,452	$ 37,611	$ (4,708)
Charges to FortisBC Inc.				
IS charges	**-**	10,363	11,781	$ (10,363)
Staff charges - insurance	**-**	39	-	(39)
Miscellaneous	**2,410**	2,410	2,342	-
	$ 2,410	$ 12,812	$ 14,123	$ (10,402)
Charges from FortisBC Inc.				
Miscellaneous	**$ 7,359**	$ 3,822	$ 3,322	$ 3,537
Charges to Fortis BC Holdings				
Staff charges - insurance	**$ -**	$ -	$ 648	$ -
Miscellaneous	**6,830**	6,780	6,360	50
	$ 6,830	$ 6,780	$ 7,008	$ 50
Charges to Caribbean Utilities Co. Limited				
Staff charges	**$ 30,111**	$ 22,219	$ 27,113	$ 7,892
Staff charges - insurance	**-**	-	120	-
	$ 30,111	$ 22,219	$ 27,233	$ 7,892
Charges from Caribbean Utilities Co. Limited				
Miscellaneous	**$ 9,022**	$ 23,849	$ 17,074	$ (14,827)
Charges to Fortis Turks and Caicos				
Staff charges	**$ 32,289**	$ 12,271	$ 42,391	$ 20,018
Staff charges - insurance	**-**	-	162	-
Miscellaneous	**3,050**	723	40	2,327
	$ 35,339	$ 12,994	$ 42,593	$ 22,345

The most significant fluctuations from our analysis of other intercompany charges for 2016 compared to 2015 are as follows:

- Staff charges to Fortis Properties decreased by $23,569, due to Fortis Properties being sold by Fortis Inc. in 2015 resulting in no further staff charges.
- Staff charges (insurance) to Fortis Properties decreased by $18,846, which reflects the decrease in insurance claim administration related to Fortis Properties' damage claims as Fortis Properties was sold in 2015.
- Miscellaneous charges from Fortis Properties decreased by $48,885, which reflects charges associated with a Fortis Properties employee's secondment to Newfoundland Power's corporate communication department in 2015.
- Staff charges (insurance) to Fortis Ontario increased by $19,078, due to the sale of Fortis Properties in 2015. After the sale a Newfoundland Power employee continued to adjudicate outstanding Fortis Property insurance claims which had been filed prior to the sale.
- Staff charges to Maritime Electric increase by $28,208, which reflects the labour and travel time charged during the transition period when a staff member assumed the position of Vice President, Customer Service with Maritime Electric in April 2016.
- Staff charges to Belize Electric Company increase by $100,242, which is related to six Newfoundland Power personnel who supplied service to Belize Electric Company in 2016. These services included an audit and engineering and technological consultation.
- Staff Charges to Fortis Turks and Caicos increased by $20,018, which is related to two Newfoundland Power personnel who supplied services to Fortis Turks and Caicos during 2016. These services included safety/work method training and management seminars with Fortis Turks and Caicos management team in preparation for renegotiating their regulatory license.

The Company did not enter into any short-term loan agreements with related parties during the year.

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 2016 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2016	Actual 2015	Actual 2014	Variance 2016-2015
Other company fees				
Other company fees	$ 2,092	$ 1,601	$ 1,791	$ 491
Regulatory hearing costs	852	1,156	859	(304)
	$ 2,944	$ 2,757	$ 2,650	$ 187
Year over year percentage change	6.8%	4.0%	30.9%	
Deferred regulatory costs				
Total deferred regulatory costs	$ 172	$ 322	$ 322	$ (150)
Year over year percentage change	-46.6%	0.0%	0.0%	

Total company fee costs for 2016 were higher than 2015 actual by $187,000. These costs were higher than 2015 due primarily to increased consultant costs for customer energy conservation programming in 2016, partially offset by lower regulatory activity. 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 2014 to 2016 is as follows:

(000's)	Actual 2016	Actual 2015	Actual 2014	Variance 2016-2015
Miscellaneous	**$ 1,082**	$ 967	$ 1,164	$ 115
Cafeteria and lunchroom Supplies	**89**	84	92	5
Promotional items	**193**	152	120	41
Computer Software	**1**	2	5	(1)
Damage claims	**196**	301	259	(105)
Community relations activities	**3**	3	1	-
Donations and charitable advertising	**202**	188	263	14
Books, magazines and subscriptions	**21**	35	33	(14)
Misc. lease payments	**34**	33	33	1
Total miscellaneous expenses	**$ 1,821**	$ 1,765	$ 1,970	$ 56
Year over year percentage change	**3.17%**	-10.41%	12.51%	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2015 to 2016 these expenses have increased by 3.17% overall.

Our procedures in this expense category for 2016 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 2016 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with Order No. P.U. 7 (1996-97), the Company filed the 2015 Conservation and Demand Management Report with the Board. This report provided a summary of 2016 CDM activities and costs as well as the outlook for 2016.

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.

In 2016, the Utilities implemented the principal changes to customer conservation programming contained in the 2016 Plan. These changes relate to (i) expansion of current programs, particularly for commercial customers; (ii) introduction of a residential benchmarking program; and (iii) development of an educational initiative to promote mini split heat pumps.

Total CDM costs in 2016 totaled $8,039,000 compared to $5,736,000 in 2015, a $2,303,000 increase. This increase is primarily due to increased customer uptake on instant rebates for items offering energy savings such as LED light bulbs.

In 2016, $7,200,000 ($5,040,000 after tax) in CDM costs were deferred to be amortized over 7 years as per Order No. P.U. 13 (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 2016 and 2015.

(000's)	Actual 2016	Actual 2015	Actual 2014	Variance 2016-2015
Vehicle expense	1,797	1,786	1,901	11
Operating materials	1,425	1,583	1,857	(158)
Inter-company charges	2,145	1,560	1,710	585
Plants, Subs, System Oper & Bldgs	2,770	2,367	2,312	403
Travel	1,160	1,052	1,318	108
Tools and clothing allowance	1,161	1,130	1,192	31
Conservation	4,253	2,466	1,762	1,787
Taxes and assessments	1,214	1,123	1,040	91
Uncollectible bills	1,194	1,313	1,490	(119)
Insurance	1,293	1,260	1,243	33
Severance & other employee costs	47	72	58	(25)
Education, training, employee fees	275	298	310	(23)
Trustee and directors' fees	471	462	431	9
Stationary & copying	266	230	266	36
Equipment rental/maintenance	838	746	769	92
Communications	2,959	3,184	3,220	(225)
Advertising	1,519	1,251	1,444	268
Vegetation management	1,820	1,766	1,789	54
Computing equipment & software	1,359	1,058	915	301
Transfers (GEC)	(2,955)	(3,809)	(3,399)	854
CDM amortization	1,712	1,053	420	659

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

- Operating materials costs were lower than 2015 due primarily to the elimination of contracted services for streetlight repairs. This work transitioned to Newfoundland Power staff during 2016.
- Inter-company charges in 2016 were higher than 2015 due to an increase in recoveries charged by Fortis. These charges are non-regulated in nature.
- Plant, subs, system operations and buildings costs in 2016 were higher than 2015 due primarily to higher taxes for hydroelectric generation as a result of the 2016 provincial budget.
- Conservation costs in 2016 were higher than 2015 due to increased customer uptake on instant rebates for items offering energy savings such as LED lightbulbs
- Communication costs in 2016 were lower than 2015 primarily due to lower third party telecommunication service provider costs reflecting favorable contract pricing, implementation of voice over internet protocol in late 2015 and there was an increase in the number of customers participating in electronic billing lowering postage costs.
- Advertising costs were higher than 2015 due to marketing associated with implementing the customer energy conservation program

- Computing equipment & software costs in 2016 were higher than 2015 due to increase in third party software licensing costs, as well as the addition of maintenance for new software purchases.
- Transfers to General Expenses Capitalized for 2016 were lower than 2015 primarily due to lower pension costs in 2016 compared to 2015.
- Conservation and Demand Management (CDM) amortization has increased from 2015. 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 2016 due to the inclusion of the third year of deferred customer energy conservation programming costs.

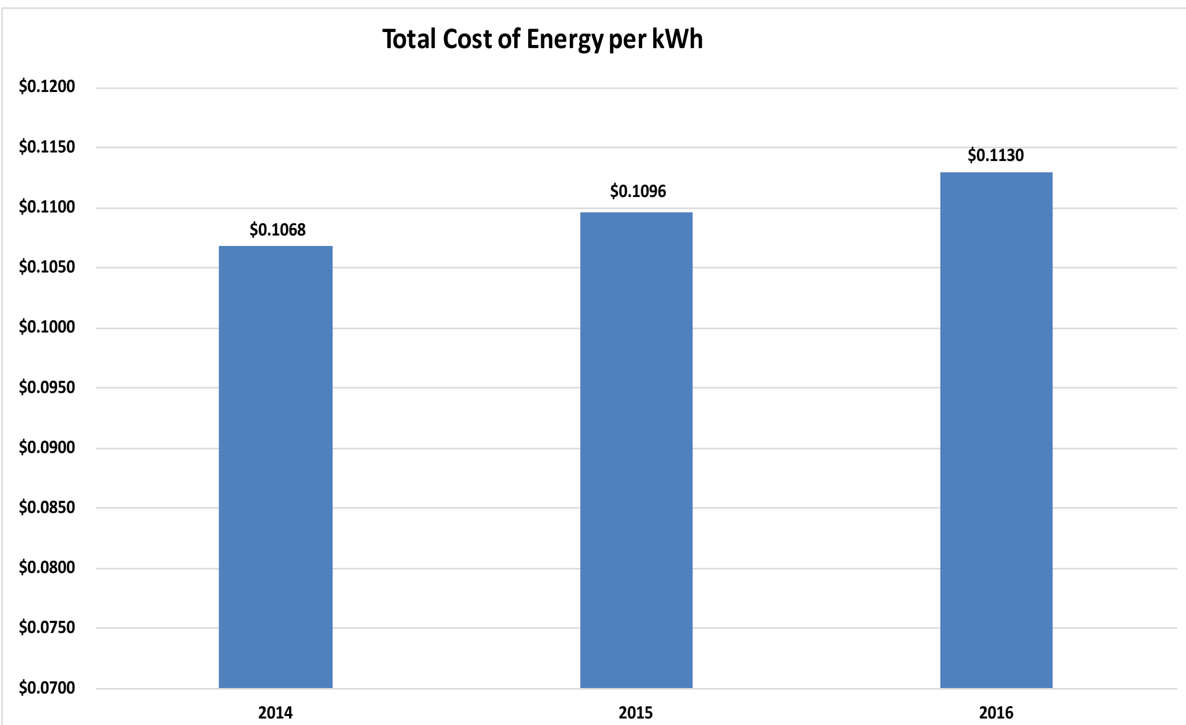
Other Costs

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 2014 to 2016:

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
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
2016	5,950,100	$ 78,690	$ 443,311	$ 2,064	$ 60,472	$ 35,235	$ 11,851	$ 40,508	$ 672,131	$ 0.1130



Purchased Power

We have reviewed the Company's purchased power expense for 2016 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 $21.2 million, from $422.1 million in 2015 to $443.3 million in 2016. According to the Company, the increase resulted primarily due to the interim wholesale rate increase which was effective July 1, 2015. The impact of this rate increase was partially offset by a reduced volume of wholesale purchases.

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, 2014 and assessed the reasonableness of depreciation expense.

In Order No. P.U. 13 (2013) the Board ordered the Company to file a new depreciation study related to plant in service as of December 31, 2014. The study for plant in service as of December 31, 2014 was completed in 2015. The study was included in the 2016-2017 General Rate Application by the Company and was approved in Order No. P.U. 18 (2016), including the approval of the accumulated depreciation reserve variance to be amortized over the average remaining service life of the related assets. The depreciation rates from the 2014 depreciation study, including the amortization of the accumulated depreciation reserve, were implemented effective January 1, 2016. Gannett Fleming has recommended the continued use of the straight line equal life group ("ELG") method in its 2014 depreciation study.

The objective of our procedures in this section was to ensure that the 2016 depreciation amounts and rates are in compliance with Board Orders, and in agreement with the recommendations of the 2014 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 2016; and,
- assessed the overall reasonableness of the depreciation for 2016.

Amortization expense for 2016 is $60,472,000 as compared to $56,720,000 for 2015, representing a 6.6% increase. The 2016 and 2015 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)	2016	2015	Variance 2016-2015	%
Depreciation and amortization as reported	$ 60,472	$ 56,720	$ 3,752	**6.6%**
Less: Tax on Cost of Removal (1)	(5,282)	(4,869)	(413)	**8.5%**
Depreciation of Fixed Assets	$ 55,190	$ 51,851	$ 3,339	**6.4%**

Note 1: Recognized as income tax for financial reporting purposes

The following table provides a comparison of the depreciation of fixed assets for 2016, 2015 and 2014:

($000's)	2016	2015	2014	Variance 2016-2015
Depreciation of Fixed Assets	$ 55,190	$ 51,851	$ 49,288	$ 3,339

Depreciation of fixed assets for 2016 is $55,190,000 as compared to $51,851,000 for 2015, representing a 6.4% increase. The change is attributable to an increase of depreciable assets by approximately $75,431,000.

Based on our review of depreciation expense, we conclude that the Company is in compliance with Order No. P.U. 19 (2003), Order No. P.U. 39 (2006), Order No. P.U. 32 (2007), Order No. P.U. 13 (2013), and Order No. P.U. 18 (2016). The recommendations and results of the Gannett Fleming Depreciation Study reported on the plant in service as of December 31, 2014 have been incorporated into the Company's depreciation calculations for 2016.

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 2014 to 2016:

(000's)	Actual 2016	Actual 2015	Actual 2014	Variance 2016-2015
Interest				
Long - term debt	$ 34,846	$ 35,020	$ 36,327	$ (174)
Other	878	1,139	645	(261)
Amortization				
Debt discount	223	242	254	(19)
Interest charged to construction	(712)	(677)	(776)	(35)
Total Finance charges	$ 35,235	$ 35,724	$ 36,450	$ (489)
Year over year percentage change	-1.37%	-1.99%	0.04%	

In the above table, finance charges decreased by approximately $0.5 million, from $35.7 million in 2015 to $35.2 million in 2016. The lower finance costs reflect interest savings associated with the maturity of $30.4 million, 10.9% first mortgage sinking fund bonds on May 2, 2016, as well as lower short-term borrowings and related interest charges in 2016. These savings were partially offset by interest costs associated with the $75 million, 4.446% first mortgage bonds issued in September 2015.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2016 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2016 and have noted that the effective income tax rate increased from 21.7% in 2015 to 22.6% in 2016. 2016, 2015 and 2014 results in the following effective rates:

	2016	2015	2014	2016-2015
Income tax expense	$ 11,851	$ 10,925	$ 10,795	$ 926
Earnings before income tax	$ 52,359	$ 50,239	$ 48,635	$ 2,120
Effective income tax rate	22.6%	21.7%	22.2%	0.9%

The effective rate increased by 0.9% in 2016 compared to 2015 primary due to a statutory tax rate increase of 1% in 2016. The Government of Newfoundland and Labrador increased the statutory tax rate from 29% to 30% effective January 1, 2016.

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 2016 is unreasonable.

Costs Associated with Curtailable Rates

In Order No. 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 Order No. 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 Order No. 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 $349,974 for the current period compare to a total of $345,837 for the same period during the previous year. Changes to the curtailment credits year over year are attributable to variation in demand and consumption, and the mix of Option participants achieving full or partial credit.

Nothing has come to our attention to indicate that the Company is not in compliance with the applicable orders of Order No. P.U. 7 (1996-97) and Order No. 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 2016 to prior years and investigated any unusual fluctuations;
* reviewed detailed listings of expenses for 2016 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 2016	Actual 2015	Actual 2014	Variance 2016-2015
Charged from Fortis Companies	**2,249,100**	1,672,000	1,990,700	577,100
Performance and restricted share units	**454,500**	276,800	147,400	177,700
Donations and charitable advertising	**283,300**	273,700	331,100	9,600
Executive short term incentive	**341,000**	272,600	285,200	68,400
Miscellaneous	**70,200**	39,100	46,500	31,100
	3,398,100	2,534,200	2,800,900	863,900
Less: Income Taxes	**1,019,400**	734,900	812,200	284,500
Total non-regulated (net of tax)	**$ 2,378,700**	$ 1,799,300	$ 1,988,700	$ 579,400

The Company has classified STI payouts in excess of 100% of target payouts and 50% portion of the earnings and regulatory performance metrics as non- regulated expenses in compliance with Order No. P.U. 19 (2003) and Order No. P.U. 18 (2016), respectively. For 2016 this represents an addition to non-regulated expenses (before tax adjustment) of $341,000 (2015 - $272,600). 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 30.0% which agrees with the Company's statutory rate as identified in the 2016 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 2015 and 2016:

(000's)	2016 Actual	2015 Actual	Variance 2016-2015
Regulatory Assets			
Rate stabilization account	**$ 4,763**	**$ 960**	$ 3,803
OPEBs asset	**31,536**	**35,040**	(3,504)
Deferred GRA costs	**682**	**-**	682
Conservation and demand management deferral	**15,999**	**10,511**	5,488
Optional seasonal rate revenue and cost recovery account	**-**	**60**	(60)
Employee future benefits	**100,757**	**113,044**	(12,287)
Weather normalization account	**2,458**	**6,212**	(3,754)
Deferred income taxes	**191,313**	**179,532**	11,781
	$347,508	**$345,359**	$ 2,149
Regulatory Liabilities			
Cost recovery deferral	**$ 2,064**	**$ -**	$ 2,064
Future removal and site restoration provision	**143,419**	**139,700**	3,719
Excess earnings	**-**	**68**	(68)
	$145,483	**$139,768**	$ 5,715

<u>Rate Stabilization Account</u>

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, 2016 were approved by the Board in Order No. P.U. 25 (2016).

As of December 31, 2016, there was a charge to the RSA of $3,134,800 related to the Energy Supply Cost Variance Reserve in accordance with Order No. P.U. 32 (2007) and Order No. P.U. 43 (2009).

Pursuant to Order No. 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, 2016, there was a balance of $Nil in this account as the actual pension expense and forecast pension expense for 2016 were equal; therefore, no transfer to the RSA was necessary.

Pursuant to Order No. 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, 2016, there was a balance of $Nil in this account as the actual pension expense and forecast pension expense for 2016 were equal; therefore, no transfer to the RSA was necessary.

Pursuant to Order No. 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, 2016 $6,212,027 was debited to the RSA in accordance with Order No. P.U. 13 (2013).

The RSA is also adjusted for the Demand Management Incentive Account ($Nil balance in 2016), 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 Order No. 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 Order No. P.U. 31(2010).

Deferred general rate application costs

In Order No. P.U. 18 (2016) the Board approved the deferral of cost related to 2016/2017 GRA as well as amortization of this deferral over a 30 month period commencing on July 1, 2016. Actual costs incurred and deferred were approximately $854,000 with amortization of $171,000 incurred in 2016.

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 Order No. P.U. 13 (2009) that these costs be deferred until a further Order of the Board. In Order No. 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 Order No. 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, 2016 were $15,999,000 with amortization of $1,711,951 in 2016.

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 Order No. 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 Order No. 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 Order No. P.U. 10 (2016). There was no balance in this account as at December 31, 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 Order No. 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 Order No. 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 Order No. 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 Order No. 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 Order No. P.U. 11 (2012), to be amortized over 15 years commencing in 2013.

As of December 31, 2016 the regulated asset for employee future benefits was $100,757,000

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.

Commencing in 2013, Order No. P.U. 13 (2013) 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 Order No. P.U. 12 (2017) the Board approved the December 31, 2016 net regulatory asset balance in the Weather Normalization Account of $2,458,000 ($1,720,705 net of future income tax).

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, 2016 was $191,313,000.

Cost Recovery Deferral

In 2016 there was an over-recovery of revenue due to a July 1, 2016 rate implementation date. In Order No. P.U. 18 (2016), the Board approved amortization from July 1, 2016 to December 31, 2018 to provide recovery in customer rates of any 2016 revenue shortfall associated with the July 1, 2016 rate implementation. The over-recovery of revenue was approximately $2,580,000 with amortization of approximately $516,000, resulting in a net regulatory liability of $2,064,000 at December 31, 2016.

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 2016 the balance in this account was $143,419,000 (2015 - $139,700,000).

Excess earnings

Excess earnings are the earnings that exceed the upper limit of the allowed range of return on rate base of 7.39% approved by the Board in Order No. P.U. 25 (2016) for 2016 and 7.68% approved by the Board in Order No. P.U. 51 (2014) for 2015. For 2016 and 2015 the Company's regulated earnings did not exceed the upper limit and therefore there is $Nil excess earnings reported on the 2016 Return 13.

Based upon our analysis, nothing has come to our attention to indicate that changes in regulatory deferrals for 2016 are unreasonable.

Pension Expense Variance Deferral Account

Scope: Review of calculation of the Pension Expense Variance Deferral Account ("PEVDA") and assess compliance with Order No. P.U. 43 (2009)

In Order No. 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 actual pension expense and the test year forecast pension expense for 2016 were equal; therefore, the balance in the PEVDA for 2016 is $Nil.

We confirm that the 2016 PEVDA is calculated in accordance with Order No. 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 Order No. P.U. 31(2010)***

In Order No. 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 actual OPEBs expense and the test year forecast OPEBs expense for 2016 were equal; therefore, the balance in the OPEBVDA for 2016 is $Nil.

We confirm that the 2016 OPEBVDA is calculated in accordance with Order No. P.U. 31 (2010).

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 2016 are as follows:

1. Made capital investments of $96 million of which over 55% 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 85% Automated Meter Reading ("AMR") penetration Island-wide. In 2016, over 51,000 AMR meters were installed. Route optimization resulted in the elimination of 171 routes by the end of 2016. This enabled meter reading labour cost savings of approximately $0.5 million compared to 2015.

5. Substantial progress was made in collecting customer and asset location data. Approximately 86% of customer connectivity data and 72% of distribution line phasing data has been compiled in the Company's Geographic Information System ("GIS"). The project is scheduled for completion in the first quarter of 2017.

6. Continued the Substation Modernization and Refurbishment program in total 75% of the distribution feeders are now automated.

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

8. During the 4th quarter, the Company implemented a lone worker monitoring solution using a Telelink smart phone application. The technology initiates regular check-ins to monitor employees exposed to medium or high risk hazards who are working alone on the job. Where cell phone service is unavailable workers carry satellite enabled devices.

9. The Company's electronic billing program grew to over 100,000 accounts in 2016, representing approximately 40% of customer accounts.

10. Customer self-service results for 2016 are 85%, above the plan and 2015. Self-service usage continues to show improvement. There was a 56% increase in online outage reporting, a 40% increase in online streetlight reporting and a 30% increase in website payment arrangements.

11. A new virtual agent technology was introduced as a pilot project in the Company's regional offices. The pilot will enable customers to directly video/audio link to a Customer Service Representative in the Contact Centre in St. John's when the regional office is fully tasked. The customer will be able to sign contracts, show IDs, and will be able to complete all regular customer service functions with this virtual agent.

12. The Company launched an automated outbound phone call technology, called Robocall, to improve customer communications and assist operations with restoration during an extended power outage on the south west coast of the island in December. The automated outbound phone calls reached over 80% of customers within seconds. The messages provided information about topics such as estimated restoration times, energy conservation, safety, and warming centers.

13. Newfoundland Power launched a smartphone app which will provide an easy and convenient way for customers to connect with the Company. Customers will be able to view their account information, access up to date information on power outages and report an outage using the app.

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 provided by Newfoundland Power lists the principal performance measures used in the management of the Company:

Category	Measure	Actual 2014	Actual 2015	Actual 2016	Plan 2016	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1]	2.93	2.36	2.24	2.36	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply[1]	2.44	2.11	1.36	1.87[5]	Yes
	Plant Availability (%)	94.4	94.9	93.2[3]	95.0	No
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	83.5	86.0	86.0	87.0	No
	Call Centre Service Level (% per second)	80/60	82/60	81/60[4]	80/60	Yes
	Trouble Call Responded to Within 2 Hours (%)	81.0	86.0	87.0	85.0	Yes
Safety	All Injury/Illness Frequency Rate	1.2	0.5	1.3	0.9	No
Financial	Earnings (millions)	$37.3	$38.8	$40.0	$38.3	Yes
	Gross Operating Cost/Customer[2]	$259	$249	$260	$260	Yes

[1] 2014 reliability statistics above exclude the impact of the January Newfoundland and Labrador Hydro (NLH) system problems. 2016 reliability statistics exclude the impact of a wind storm in December.
[2] Excludes pension, OPEBs and early retirement costs.
[3] 93.1 per Q4 Quarterly Regulatory Report. Difference does not impact whether the measure was achieved.
[4] 82/60 per Q4 Quarterly Regulatory Report. Difference does not impact whether the measure was achieved.
[5] 1.93 per Q4 Quarterly Regulatory Report. Difference does not impact whether the measure was achieved.

The following table compares whether the company measures were achieved during the 2014, 2015, and 2016 years:

Category	Measure	Measure Achieved 2014	Measure Achieved 2015	Measure Achieved 2016
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply	No	Yes	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply	No	No	Yes
	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 (%)	No	Yes	Yes
Safety	All Injury/Illness Frequency Rate	Yes	Yes	No
Financial	Earnings (millions)	Yes	Yes	Yes
	Gross Operating Cost/Customer	No	Yes	Yes