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NP 2019-2020 General Rate Application
Information Item - #3
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Board of Commissioners of Public Utilities
2017 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 2017 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 2017 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 2017 was $1,092,254,000 compared to average rate base for 2016 of $1,061,044,000. The Company's calculation of the return on average rate base for 2017 was 7.22% (2016 – 7.31%) compared to an approved rate of return of 7.19%. The actual rate of return was within the range approved by the Board (7.01% to 7.37%). 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 2017 was $486,557,000 (2016 - $475,765,000). The Company's actual return on average common equity for the year ended December 31, 2017 was 8.93% (2016 – 8.90%). 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 2017 the cost of common equity was 8.50% as per Order No. P.U. 18 (2016). The actual return on average common equity for 2017 was 8.93% 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 12.14% under budget in 2017. The capital expenditures were under the approved budget (including projects carried over from prior years) on a net basis by $9,886,000 (6.79%). However, for each category of expenditure, the variances ranged from an over-budget of 6.54% to an under-budget of 32.74%. Significant variances are explained in our report.

The Company experienced a 0.08% increase in revenue from rates in 2017 as compared to 2016. The increase can be explained by the full year impact of an increase in customer energy rates effective July 1, 2016 related to the Company's 2016/2017 General Rate Application ("GRA"), partially offset by a decrease in GWh sold.

Overall, net operating expenses increased by $1,782,000 from 2016 to 2017. 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 2017 are unreasonable.

Our review of non-regulated expenses resulted in nothing coming to our attention to indicate that the amounts reported are unreasonable or not in accordance with Board Orders.

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 2017 the Company met seven out of nine of its planned performance measures. The Company fell short of its targets in the following categories: "Plant Availability" and "% of Satisfied Customers as measured by Customer Satisfaction Survey".

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2017 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 2017 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 2016-17 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, 2017 have been audited by Deloitte LLP, Chartered Professional Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 14, 2018. 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 29, 2018, the Company filed a revised system of accounts as part of its 2017 Annual Report. According to Newfoundland Power, the revisions principally relate to minor wording changes to improve clarity and accuracy of account descriptions and two accounts that were inadvertently deleted last year were reinstated. These changes are not significant and the Company believes it will enhance its ability to provide sufficient information to meet the reporting requirements of the Board.

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, 2017 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 2017 was $1,092,254,000 which is an increase of $31,210,000 (2.94%) over the average rate base for 2016 of $1,061,044,000. 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 2017; 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 2017, 2017 Test Year and 2016 (all figures shown are averages):

(000)'s	2017	2017 Test Year	2016
Net Plant Investment (average)			
Plant Investment	$1,772,877	-	$1,703,478
Accumulated Depreciation	(709,985)	-	(681,742)
CIAC's	(37,234)	-	(35,166)
	1,025,658	1,041,415	986,570
Additions to Rate Base (average)			
Deferred Charges (a)	93,498	94,045	96,877
Cost Recovery Deferral for Seasonal/TOD Rates (b)	-	-	25
Cost Recovery Deferral for Hearing Costs (c)	512	600	341
Cost Recovery Deferral – Conservation (d)	12,710	11,991	9,384
Customer Finance Programs (e)	1,419	1,136	1,276
Demand Management Incentive Account (f)	745	-	-
Weather Normalization Reserve (g)	3,246	-	3,066
	112,130	107,772	110,969
Deductions from Rate Base (average)			
Other Post-Employment Benefits (h)	49,334	48,719	42,646
Customer Security Deposits (i)	926	700	1,036
Accrued Pension Obligation (j)	5,429	5,428	5,120
Deferred Income Taxes (k)	3,051	3,728	1,727
Excess Earnings (l)	-	-	25
Cost Recovery Deferral – 2016 Cost Recovery Deferral (m)	1,084	1,099	723
	59,824	59,674	51,277
Average Rate Base before Allowances	1,077,964	1,089,513	1,046,262
Rate Base Allowances			
Materials and Supplies	6,137	6,788	6,464
Cash Working Capital	8,153	8,401	8,318
	14,290	15,189	14,782
Average Rate Base	$ 1,092,254	$ 1,104,702	$ 1,061,044

(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 $93,498,000 (2016 - $96,877,000) included in the 2017 rate base consists of average deferred pension costs of $93,396,000 (2016 - $96,802,000) and credit facility costs of $102,000 (2016 - $75,000). 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". In the 2016/2017 GRA, the company did not propose that the Optional Seasonal Rate Revenue and Cost Recovery Account be maintained beyond 2015.

(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 $341,000 was recorded in 2017, relating to these costs. The 2017 average rate base includes an addition of $512,000 (2016 - $341,000) which represents the unamortized average balance of the original $853,000.

(d) 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. The actual costs incurred and deferred in 2017 were $6,759,000 ($4,731,000 after tax) resulting in additional annual amortization of $676,000 to commence in 2018. Included in the calculation of the average rate base for 2017 is $12,710,000 (2016 - $9,384,000) related to this deferral.

(e) Customer Finance Programs are comprised of loans provided to customers related to customer conservation programs and contributions in aid of construction. The 2017 average rate base incorporates $1,419,000 (2016 - $1,276,000) related to these programs.

(f) The 2016 balance of the Demand Incentive Account was $Nil as there was no supply cost variance outside the Deadband. In Order No. P.U. 10 (2018) the Board approved the disposition of the 2017 balance of the Demand Incentive Account of $2,128,000 ($1,490,000 after tax) by means of a debit to the Rate Stabilization Account as of March 31, 2018. The 2017 average rate base incorporates $745,000 (2016 - $Nil) related to this account.

(g) During 2017, 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 $1,721,000 in 2017 (2016 – $4,411,000 increase).

Other transfers:

i. $112,000 transfer increase (2016 – $102,000 increase) to the reserve related to the after tax impact of the Degree Day Normalization Reserve Transfer.

ii. $4,883,000 transfer decrease (2016 - $1,823,000 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 $3,050,000 (2016 - $2,690,000 decrease). The ending balance in this reserve account totaled ($4,771,000) compared to a balance of ($1,721,000) at December 31, 2016 (an average of ($3,246,000) for 2017 (2016 – ($3,066,000)).

(h) Other Post-Employment Benefits is equal to the difference, at December 31, 2017, between the OPEBs liability of $80,616,000 and the OPEBs asset of $28,032,000. The calculation of the 2017 average rate base of $49,334,000 is equal to the average of the December 31, 2017 net liability of $52,584,000 and the December 31, 2016 net liability of $46,083,000.

(i) 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 2017 average rate base incorporates $926,000 (2016 - $1,036,000) related to customer security deposits.

(j) The 2017 average rate base calculation incorporates $5,429,000 (2016 - $5,120,000) 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.

(k) 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 2017 average rate base is ($2,297,000) and ($13,176,000) respectively. The remaining balance of the deferred income tax liability in the amount of $18,523,000 relates to capital assets. This results in an average balance for deferred income tax liability of $3,051,000 (2016 - $1,727,000).

(l) 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 2017 average rate base incorporates $Nil (2016 - $25,000) related to this account.

(m) 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 ($722,000) was recorded in 2017, relating to this over-recovery of revenue. The 2017 average rate base includes deduction of $1,084,000 (2016 - $723,000) which represents the unamortized average balance of the original $1,806,000.

The net change in the Company's average rate base from 2016 to 2017 can be summarized as follows:

(000's)	**2017**	**2016**
Average rate base - opening balance	**$ 1,061,044**	**$ 1,019,082**
Change in average deferred charges and deferred regulatory costs	**(268)**	**(3,375)**
Average change in:		
Plant in service	**69,398**	**74,289**
Accumulated depreciation	**(28,243)**	**(24,509)**
Contributions in aid of construction	**(2,068)**	**(1,197)**
Weather normalization reserve	**181**	**1,681**
Other post employment benefits	**(6,688)**	**(6,824)**
Future income taxes	**(1,324)**	**172**
Rate base allowances	**(492)**	**1,763**
Demand Management Incentive Acct	**745**	**-**
Other rate base components (net)	**(31)**	**(38)**
Average rate base - ending balance	**$ 1,092,254**	**$ 1,061,044**

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2017 average rate base, and therefore conclude that the 2017 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 2017 was 7.22% (2016 – 7.31%). 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 2017, 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 2015 to 2017 is set out in the table below.

	2017	2016	2015
Actual Return on Average Rate Base	7.22%	7.31%	7.48%
Upper End of Range set by the Board	7.37%	7.39%	7.68%
Lower End of the Range set by the Board	7.01%	7.03%	7.32%

The Board approved the Company's rate of return on average rate base of 7.19% in a range of 7.01% to 7.37% for 2016 in Order No. P.U. 25 (2016). As noted above, the Company's actual return on average rate base for 2017 was 7.22% which was inside the range set by the Board.

The actual rate of return for 2016 was within the range set by the Board.

The actual rate of return for 2015 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 2017 as reported in Return 24 is as follows:

	2017 Average		2016	2015
	(000's)	Percent	Percent	Percent
Debt	**$586,726**	**54.22%**	54.17%	54.85%
Preferred equity	**8,924**	**0.82%**	0.84%	0.88%
Common equity	**486,557**	**44.96%**	44.99%	44.27%
	$1,082,207	**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 2017 test year in Return 26. The embedded cost of debt for 2017 was 6.12% which represents a 15 bps decrease from 2016 embedded cost of debt of 6.27%.

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, 2017 is included on Return 27 of the annual report to the Board. The average common equity for 2017 was $486,557,000 (2016 - $475,765,000). The Company's actual return on average common equity for 2017 was 8.93% (2016 – 8.90%).

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 2017 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 2017 the cost of common equity was 8.50% as per Order No. P.U. 18 (2016). The actual return on average common equity for 2017 was 8.93% 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)	2017	2016	2015
Net income	**$41,526**	$ 40,508	$ 39,314
Income taxes	**12,882**	11,851	10,925
Interest on long term debt	**35,013**	34,846	35,020
Interest during construction	**(1,025)**	(1,304)	(1,240)
Other interest and amortization of debt discount costs	**893**	1,090	1,361
Total	**$89,289**	$ 86,991	$ 85,380
Interest on long term debt	**$35,013**	$34,846	$35,020
Other interest and amortization of debt discount costs	**893**	1,090	1,361
Total	**$35,906**	$35,936	$36,381
Interest Coverage (times)	**2.5**	2.4	2.3

The above table shows that the interest coverage increased by 0.1 times from 2016 to 2017.

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 2017 is 2.5 times.

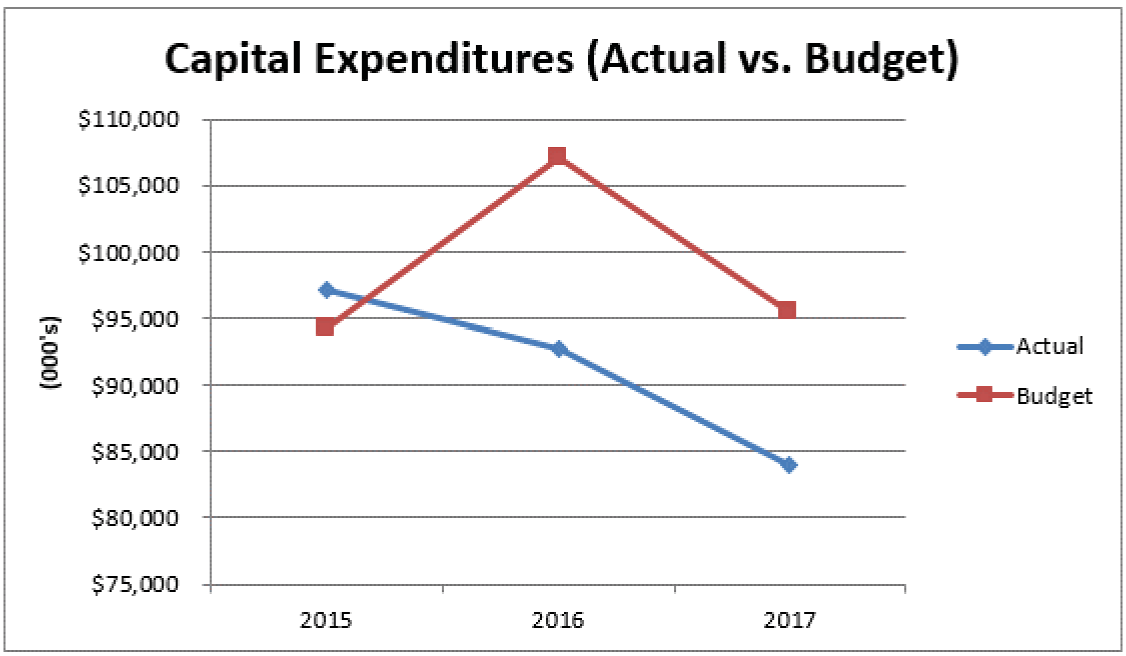
Capital Expenditures

Scope: ***Review the Company's 2017 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 2015 to 2017:

($000's)	2015	2016	2017	Notes
Actual	$ 97,155	$ 92,727	$ 83,921	1
Budget	$ 94,211	$ 107,028	$ 95,521	
Over (under) budget	3.12%	(13.36%)	(12.14%)	

Note 1: Total expenditures per the 2017 Capital Budget report includes the carryover amount of $5,770,000 for a total of $89,691,000. The carryover amount is made up of five projects included in the following categories: $1,476,000 to generation - hydro; $750,000 to substations; $475,000 to transmission; $2,846,000 to distribution and $223,000 to Transportation. According to the Company, these expenditures will occur in 2018.



The following table provides a summary of the capital expenditure activity in 2017 as reported in the Company's *"2017 Capital Expenditure Report"*:

($000's)	Capital Budget			Actual Expenditures		
	Prior Years	2017	Total	Prior Years	2017	Total
2017 Capital Projects (1)	$ -	$ 95,521	$ 95,521	$ -	$ 83,921	$ 83,921
2016 Projects Carried to 2017 & Multi Year Projects						
Facility Rehabilitation - 2016 (2)	1,462	-	1,462	1,252	619	1,871
Public Safety Around Dams - 2016	883	-	883	559	413	972
Substation Refurbishment and Modernization - 2016 (3)	7,871	-	7,871	5,980	914	6,894
Transmission Line Rebuild - 2016 (4)	6,067	-	6,067	4,046	140	4,186
Distribution Reliability Initiative - 2016	1,463	-	1,463	359	1,093	1,452
Distribution Feeder Automation - 2016 (5)	565	-	565	265	99	364
Trunk Feeders - 2016 (6)	1,607	-	1,607	1,134	14	1,148
St. John's Main Underground Refurbishment - 2016	1,950	-	1,950	326	1,624	1,950
Purchase Vehicles and Aerial Devices - 2016	3,258	-	3,258	2,353	1,024	3,377
Fibre Optic Network - 2016 (7)	409	-	409	109	120	229
Application Enhancements - 2016	1,143	-	1,143	989	154	1,143
System Upgrades - 2016	1,718	-	1,718	1,244	390	1,634
Pierre's Brook Plant Refurbishment - Multi Year	15,762	-	15,762	14,793	239	15,032
SCADA System Replacement - Multi Year	5,675	-	5,675	5,335	276	5,611
OMS System Replacement - Multi Year (8)	149	-	149	63	-	63
	49,982	-	49,982	38,807	7,119	45,926
Grand Total	**$ 49,982**	**$ 95,521**	**$ 145,503**	**$ 38,807**	**$ 91,040**	**$ 129,847**

(1) Approved by Order No. P.U. 39 (2016), Order No. P.U. 6 (2017), and Order No. P.U. 19 (2017).
(2) The Company has noted that the unfavorable budget variance was primarily related to the higher than average expenditure on equipment replacements due to in-service failures, as it was $198,000 higher than the historical average.
(3) The Company has noted that the favorable variance was related to the fact that cost estimates assumed that most of the work would be done by contractors. However, due to lower than anticipated substation maintenance requirements during the year, Company personnel were able to complete much of the construction and commissioning work.
(4) The Company has noted that the favorable budget variance primarily resulted from the corduroy road project being completed during the 2015 portion and therefore no additional expenditures were required in 2016. The variance was also contributed to by lower than expected contractor pricing and identified deficiencies in 2016 costing $300,000 less than the historical averages.
(5) The Company has noted that the budget variance is a result of installations that were delated until 2017 because several pieces of equipment failed factory acceptance testing.
(6) The Company has noted that the favorable budget variance was principally due to the elimination of a requirement to upgrade the vault at the old Battery Hotel when the property was purchased by MUN.
(7) The Company has noted that the favorable budget variance is related to reduced materials and labor requirements for the project as the final route identified during detailed engineering was shorter than the route used to prepare the budget estimate.
(8) The Company has noted that the variance is related to the initial stage of the 2016/2017 project involving a market assessment of outage management systems and the development of a detailed system specification. However, following the initial assessment it was decided that a different scope was necessary and as a result, the Company submitted a revised project as part of its 2018 Capital Budget Application.

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

($000's)	2017 Budget (1)	2017 Actuals (2)	Variance	Carryover	Variance Including Carryover	%
Generation - Hydro	$ 25,133	$ 22,559	$ (2,574)	$ 1,476	$ (1,098)	(4.37%)
Generation - Thermal	234	242	8	-	8	3.42%
Substation	26,110	22,371	(3,739)	750	(2,989)	(11.45%)
Transmission	12,778	10,410	(2,368)	475	(1,893)	(14.81%)
Distribution	53,802	48,367	(5,435)	2,846	(2,589)	(4.81%)
General property	1,502	1,456	(46)		(46)	(3.06%)
Transportation	6,714	6,930	216	223	439	6.54%
Telecommunications	507	341	(166)	-	(166)	(32.74%)
Information systems	13,973	13,204	(769)	-	(769)	(5.50%)
Unforeseen	750	-	(750)	-	(750)	(100.00%)
General expenses capitalized	4,000	3,967	(33)	-	(33)	(0.83%)
Total	**$ 145,503**	**$ 129,847**	**$ (15,656)**	**$ 5,770**	**$ (9,886)**	**(6.79%)**

1 - Includes prior years projects and current year budgeted amounts as there were projects incomplete at the previous year ends.
2 - 2017 actuals include the total expense for projects carried forward from the years 2015 to 2016.

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 $15,656,000 and by $9,886,000 (6.79%) when carryover amounts are taken into account. However, for each category of expenditure, the variances ranged from an over-budget of 6.54% for the Transportation category to an under-budget of 32.74% 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		314
Rose Blanche Plant Refurbishment		280
Tors Cove Plant Refurbishment		882
Substation Refurbishment and Modernization		750
Transmission Line Rebuild		475
Meters		300
Distribution Reliability Initiative		700
Distribution Feeder Automation		420
St. John's Main Underground Refurbishment		1,426
Purchase Vehicles and Aerial Devices		223
Total Carryover	**$**	**5,770**

The Company has provided detailed explanations on budget to actual variances in its "2017 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 2017 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 -13.36% in 2016 and -12.14% in 2017. According to Newfoundland Power, this is related to the fact that for both years, there were significant carryovers for work not completed on schedule. In 2016, there were forecast carryovers totaling $7,284,000 which reduced the variance to 6.56%. Actual 2016 capital expenditures in 2017 associated with these carryovers were $7,319,000 resulting in a 6.52% variance for 2016 capital projects. Likewise, in 2017, there were forecast carryovers totaling $5,770,000 as seen above. This reduced the variance from 12.19% to 6.1%.

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.

<u>Capital Expenditure Reports</u>

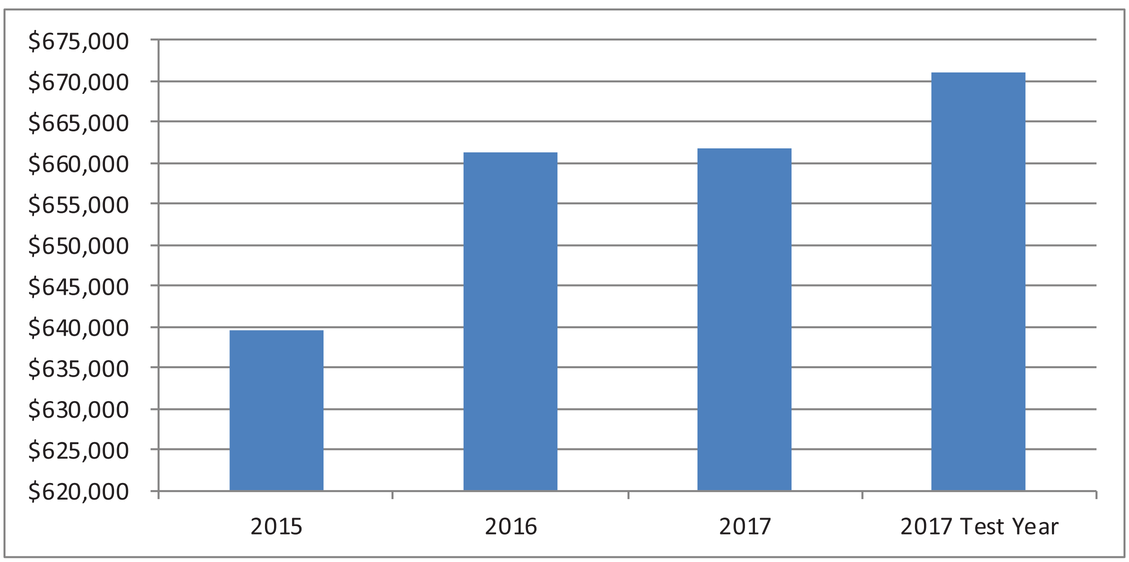
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2017 calendar year.

Revenue

Scope: Review the Company's 2017 revenue in comparison to prior years and follow up on any significant variances.

We have compared the actual revenues for 2015 to 2017 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

($000's)	2015	2016	2017	2017 Test Year
Residential	$ 403,910	$ 420,159	$ 422,237	$ 428,105
General Service				
0-100 kW	85,093	88,362	88,507	90,164
110-1000 kVA	93,725	96,404	95,565	97,515
Over 1000 kVA	38,400	38,021	37,099	36,214
Streetlighting	15,541	15,928	16,149	16,110
Discounts forfeited	2,962	2,507	2,327	2,897
Revenue from rates	$ 639,631	$ 661,381	$ 661,884	$ 671,005
Year over year percentage change	3.25%	3.29%	0.08%	1.36%



The above graph demonstrates that the Company has seen a 0.08% increase in revenue from rates in 2017 as compared to 2016. The increase is primarily due to the full year impact of an increase in customer energy rates effective July 1, 2016 related to the Company's 2016/2017 GRA, partially offset by a decrease in GWh sold. There was a 0.47% decrease in the overall demand in GWh for 2017. For residential sales there was an increase of 0.49% in 2017 revenue from 2016.

The comparison by rate class of 2017 actual revenues to 2017 budget is as follows:

($000's)	2016	2017	2017 Plan	Actual - Plan Variance	%
Residential	$ 420,159	$ 422,237	$ 426,897	$ (4,660)	(1.09%)
General Service					
0-100 kW	88,362	88,507	90,314	(1,807)	(2.00%)
110-1000 kVA	96,404	95,565	97,534	(1,969)	(2.02%)
Over 1000 kVA	38,021	37,099	36,228	871	2.40%
Streetlighting	15,928	16,149	16,116	33	0.20%
Discounts forfeited	2,507	2,327	2,895	(568)	(19.62%)
Total revenue from rates	$ 661,381	$ 661,884	$ 669,984	$ (8,100)	(1.21%)

We have also compared the 2017 budget energy sales in GWh to the actual sold in 2017:

	2016	2017	2017 Plan	Actual - Plan Variance	%
Residential	3,655.6	3,644.8	3,675.9	(31.1)	(0.85%)
General Service					
0-100 kW	797.7	793.6	811.2	(17.6)	(2.17%)
110-1000 kVA	1,010.4	1,010.2	1,027.9	(17.7)	(1.72%)
Over 1000 kVA	453.8	440.8	433.1	7.7	1.78%
Streetlighting	32.6	32.8	32.8	-	0.00%
Total	5,950.1	5,922.2	5,980.9	(58.7)	(0.98%)

Actual 2017 revenue from rates was lower than 2017 Plan with an overall decrease in actual sales of $8,100,000 (1.21%) from the 2017 Plan. There was a 0.98% decrease in GWh sold in 2017 compared to 2017 Plan. The largest variance in revenue can be seen in the Residential and 110-1000 KVA class where revenues decreased by $4,660,000 (1.09%) and $1,969,000 (2.02%) 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.

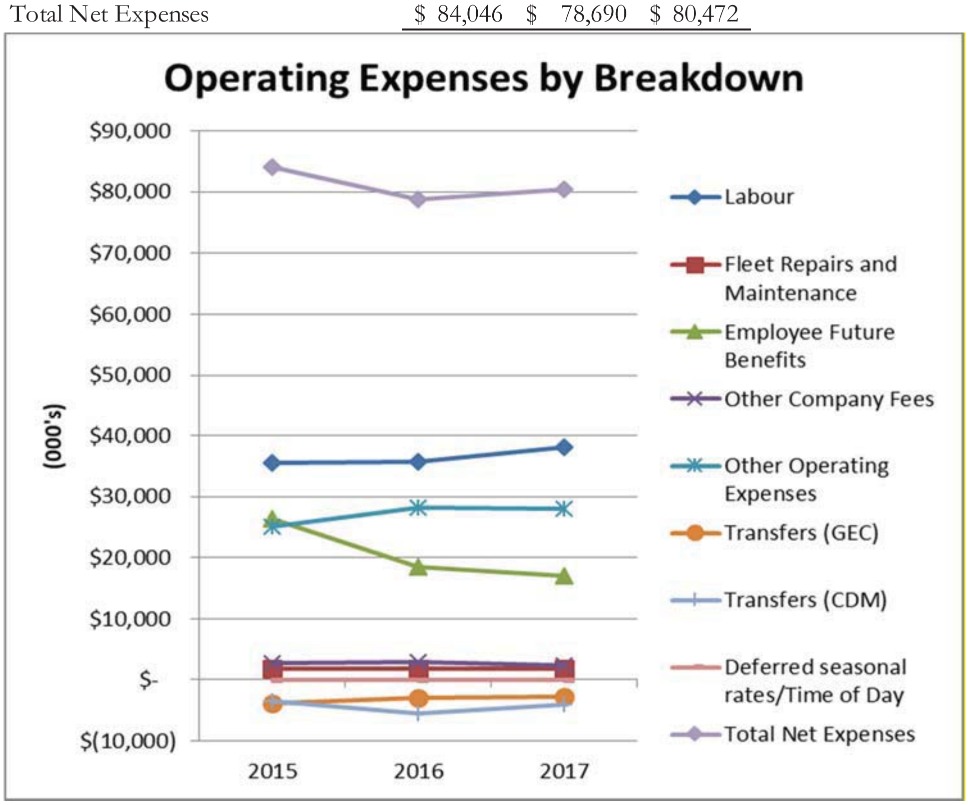
(000's)	Actual 2017	Test Year 2017	Actual 2016	Actual 2015	Variance Actual-Test	Variance 2017-2016
Labour	$ 39,341		$ 36,770	$ 36,485	$ -	$ 2,571
Reclass OPEB labour cost	(1,173)		(981)	(969)	-	(192)
Total Labour	38,168	37,956	35,789	35,516	212	2,379
Vehicle expense	1,854	1,586	1,797	1,786	268	57
Operating materials	1,528	1,674	1,425	1,583	(146)	103
Inter-company charges	2,002	2,295	2,145	1,560	(293)	(143)
Plants, Subs, System Oper & Bldgs	2,796	2,314	2,770	2,367	482	26
Travel	1,235	1,274	1,160	1,052	(39)	75
Tools and clothing allowance	1,234	1,155	1,161	1,130	79	73
Miscellaneous	1,879	1,994	1,821	1,765	(115)	58
Conservation	2,981	2,895	4,253	2,466	86	(1,272)
Taxes and assessments	1,252	1,173	1,214	1,123	79	38
Uncollectible bills	1,386	1,337	1,194	1,313	49	192
Insurance	1,326	1,266	1,293	1,260	60	33
Severance & other employee costs	102	74	47	72	28	55
Education, training, employee fees	339	363	275	298	(24)	64
Trustee and directors' fees	489	476	471	462	13	18
Other company fees	2,296	3,265	2,944	2,757	(969)	(648)
Stationary & copying	214	285	266	230	(71)	(52)
Equipment rental/maintenance	806	819	838	746	(13)	(32)
Communications	2,927	3,201	2,959	3,184	(274)	(32)
Advertising	1,592	1,717	1,519	1,251	(125)	73
Vegetation management	2,099	1,863	1,820	1,766	236	279
Computing equipment & software	1,451	1,455	1,359	1,058	(4)	92
Total Other	31,788	32,481	32,731	29,229	(693)	(943)
Pension & early retirement program	8,675	7,622	9,763	17,702	1,053	(1,088)
OPEB's	8,364	8,228	8,678	8,653	136	(314)
Total employee future benefits	17,039	15,850	18,441	26,355	1,189	(1,402)
Total gross expenses	86,995	86,287	86,961	91,100	708	34
Transfers (GEC)	(2,847)	(2,944)	(2,955)	(3,809)	97	108
CDM amortization	2,741	2,533	1,712	1,053	208	1,029
Deferred CDM program costs	(6,758)	(7,231)	(7,200)	(4,611)	473	442
Deferred seasonal rates/TOD	-	-	-	(9)	-	-
Deferred regulatory costs	341	400	172	322	(59)	169
Total net expenses	$ 80,472	$ 79,045	$ 78,690	$ 84,046	$ 1,427	$ 1,782

The above table provides details of operating and general expenses (including non-regulated expenses) by "breakdown" for 2015, 2016, 2017 Test Year and 2017 Actual.

Overall, net operating expenses increased by $1,782,000 from 2016 to 2017. 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 2017 are unreasonable. Actual net operating expenses were also higher than the test year amount by $1,427,000. The increase in actual compared to test year is primarily a result of the pension and early retirement program expense as, according to the Company, there was a lower expected return on plan assets for 2017. This increase was somewhat offset by lower than expected costs related to defined contribution plans.

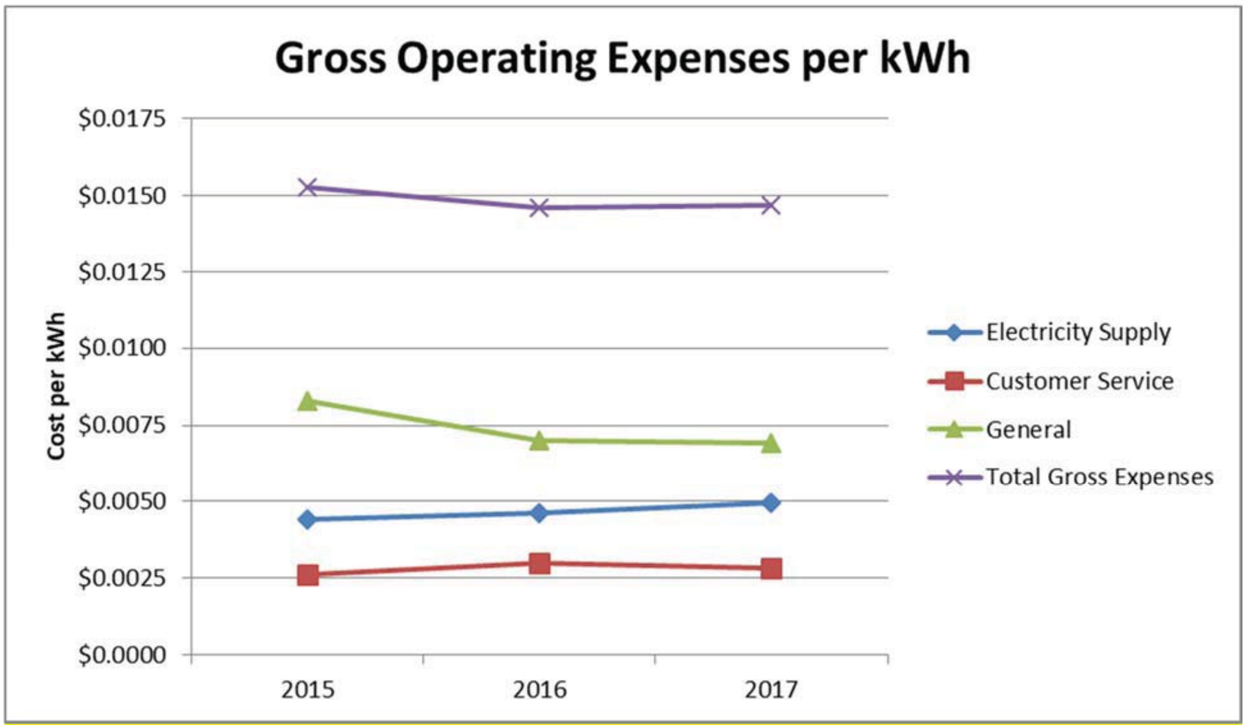
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph shows the trend in operating expenses by breakdown for the period 2015 to 2017.

	Actual		
(000's)	**2015**	**2016**	**2017**
Labour	$ 35,516	$ 35,789	$ 38,168
Fleet Repairs and Maintenance	1,786	1,797	1,854
Employee Future Benefits	26,355	18,441	17,039
Other Company Fees	2,757	2,944	2,296
Other Operating Expenses	25,008	28,162	27,979
Transfers (GEC)	(3,809)	(2,955)	(2,847)
Transfers (CDM)	(3,558)	(5,488)	(4,017)
Deferred seasonal rates/Time of Day	(9)	-	-
Total Net Expenses	$ 84,046	$ 78,690	$ 80,472



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2015 to 2017 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
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
2017	5,922,200	$ 29,352	$ 0.0050	$ 16,754	$ 0.0028	$ 40,889	$ 0.0069	$ 86,995	$ 0.0147



The table and graph show that total gross expenses per kWh have increased by approximately 0.68% compared to 2016.

There was a decrease in General Costs of $0.7 million and Customer Service Costs of $0.9 million which were offset by an increase in Electricity Supply Costs of $2.0 million. 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 2015 to 2017 (including 2017 plan) is as follows:

	Actual 2017	Plan 2017	Actual 2016	Actual 2015	Actual - Plan	Actual 2017-2016
Executive Group	**6.3**	**6.0**	6.0	6.0	0.3	0.3
Corporate Office	**20.0**	**21.8**	20.7	20.7	(1.8)	(0.7)
Finance	**88.9**	**91.5**	89.5	93.5	(2.6)	(0.6)
Egineering and Operations	**365.4**	**384.4**	406.9	418.5	(19.0)	(41.5)
Customer Relations	**84.3**	**90.0**	62.8	68.0	(5.7)	21.5
	564.9	**593.7**	585.9	606.7	(28.8)	(21.0)
Temporary employees	**46.3**	**37.8**	48.6	46.3	8.5	(2.3)
Total	**611.2**	**631.5**	634.5	653	(20.3)	(23.3)

The overall number of FTE's in 2017 compared to 2016 decreased by 23.3. The budgeted number of FTE's in the 2017 Plan was 631.5 versus actual of 611.2. The variances between 2017, 2017 Plan and 2016 are the result of the following:

- The Corporate Office is lower than plan due to timing of replacement hires for employee leaves.
- Finance is consistent with 2016 but lower than plan due to a shift of personnel to Engineering & Operations and Customer Relations as well as timing of replacement of personnel. The decrease is partially offset by the addition of a new Corporate Counsel position and a shift from contracted services for Technology.
- Engineering and operations is lower than plan and 2016 primarily due to the timing of replacement of personnel for retirements and leaves, as well as a reduction in Powerline Technicians and Engineering Technologists due to less load growth.
- Customer Relations is higher than 2016 due to a corporate reorganization to centralize customer service and meter positions under Customer Relations. 2017 is lower than plan due primarily to a shift in Customer Service Representatives from regular to temporary employees
- Temporary Employees is higher than plan because of a shift in Customer Service Representatives from regular to temporary employees. 2017 is lower than 2016 as the increase in Customer Service Representatives is more than offset by lower Meter Readers.

An analysis of salaries and wages by type of labour and by function from 2015 to 2017 is as follows:

(000's)	**Actual 2017**	Actual 2016	Actual 2015	**Variance 2017-2016**
Type				
Internal labour	**$ 64,399**	$ 63,608	$ 63,330	$ 791
Overtime	**6,807**	4,925	5,117	1,882
	71,206	68,533	68,447	2,673
Contractors	**12,883**	10,593	15,232	2,290
	$ 84,089	$ 79,126	$ 83,679	4,963
Function				
Operating	**$ 39,341**	$ 36,770	$ 36,485	2,571
Capital and miscellaneous	**44,748**	42,356	47,194	2,392
Total	**$ 84,089**	$ 79,126	$ 83,679	4,963
Year over year percentage change	6.27%	-5.44%	-4.40%	

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 2017 were $4,963,000 (6.27%) higher than 2016.

Internal labour costs in 2017 were higher than 2016 due to normal labour inflation, restoration efforts following storms and higher corporate costs. This increase was partially offset by labour efficiencies including implementation of the Automated Meter Reading strategy and an increase in contract labour for capital work.

Overtime in 2017 was higher than 2016 primarily due to restoration costs and normal labour inflation.

Contract labour for 2017 was higher than 2016 due to increased distribution work including distribution reliability initiatives and 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 2015 to 2017 are included in the table below:

	Salary Cost Per FTE			
	Actual 2017	Actual 2016	Actual 2015	Variance 2017-2016
Total reported internal labour costs	**$ 64,399**	$ 63,608	$ 63,330	$ 791
Benefit costs (net)	**(8,960)**	(8,470)	(7,559)	(490)
Other adjustments	**(1,171)**	(772)	(605)	(399)
Base salary costs	**54,268**	54,366	55,166	(98)
Less: executive compensation	**(2,016)**	(1,864)	(1,750)	(152)
Base salary costs (excluding executive)	**$ 52,252**	$ 52,502	$ 53,416	$ (250)
FTE's (including executive members)	**611.2**	634.5	653.0	
FTE's (excluding executive members)	**606.9**	630.5	649.0	
Average salary per FTE	**88,789**	85,683	84,481	
% increase	**3.62%**	1.42%	3.66%	
Average salary per FTE (excluding executive members)	**86,097**	83,271	82,305	
% increase	**3.39%**	1.17%	4.12%	

The above analysis indicates that the rate of increase in average salary per FTE for 2017 has increased from 2016 and is more in line with 2015.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2015 to 2017 and the targets set for 2017:

Short Term Incentive (STI) Program

Measure	Target 2017	Actual 2017	Actual 2016	Actual 2015
Controllable Operating Costs/Customer	**$227.40**	$228.80	$219.70	$219.80
Earnings	**39.1m**	41.0m	40.0m	38.8m
Reliability - Duration of Outages (SAIDI)	**2.30**	2.28	2.24	2.36
Customer Satisfaction - % Satisfied	**86.1%**	86.5%	86.1%	86.1%
Injury Frequency Rate	**0.35**	0.18	0.4	0.18
Regulatory Performance	**Subjective**	120%	140%	140%

2017 STI results were adjusted to remove the impact of severe weather conditions in March and December. The Company indicated that Regulatory performance is evaluated on a subjective basis, as it is difficult to apply a statistical or a simple cost based analyses. For 2017, according to the company the key determinants of the result of 120% were as follows:

i. The Board's approval of the Company's:
   - 2018 Capital Budget Application in the 4th quarter
   - New net metering service option which was implemented on July 1, 2017
   - July 1st annual rate stabilization adjustment and flow-through of final rates resulting from Newfoundland and Labrador Hydro's (Hydro) 2013 amended General Rate Application ("GRA")
   - 2018 forecast average rate base and rate return on average rate base

ii. The Company's participation in Hydro's Board applications, which include:
   - Hydro's 2013 amended GRA, including the flow-through of final rates to the company's customers on July 1, 2017
   - Hydro's application to recover approximately $42 million in 2015 and 2016 fuel expenditures associated with its 120 MW combustion turbine
   - Hydro's 2018 Capital Budget Application
   - Hydro's ongoing 2017 GRA.

Further, according to the Company it refunded over $134 million (Inclusive of taxes) to its current and former customers. The refund arose from over collections in the Hydro rate stabilization plan ("RSP") for the period 2007 to 2013. By year end, 93% of the total RSP refund was disbursed by the Company.

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 2017 is established as a percentage of base pay for the three employee groups. For 2017, measures relating to 'Earnings', 'SAIDI', 'Customer Satisfaction', 'Safety', and 'Regulatory Performance' metrics were met, however, 'Controllable Operating Costs/Customer' metric fell below target.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2015 to 2017:

	Target 2017	Actual 2017	Target 2016	Actual 2016	Target 2015	Actual 2015
President	50%	66.32%	50%	67.20%	50%	64.90%
Executive	40%	57.28%	40%	53.90%	40%	51.90%
Directors	15%	20.03%	15%	19.60%	15%	19.60%

STI actual payout rates for 'Executive' and 'Director' employee groups are higher than the prior year and each payout rate exceeded target consistent with 2016 and 2015.

In dollar terms, the STI payouts for 2015 to 2017 are as follows:

	Actual 2017	Actual 2016	Actual 2015	Variance 2017-2016
President	**$ 240,396**	$ 242,000	$ 227,000	$ (1,604)
Executive	**506,604**	442,000	401,000	64,604
Directors	**332,999**	323,300	342,200	9,699
Total	**$ 1,079,999**	$ 1,007,300	$ 970,200	$ 72,699
Year over Year % change	7.22%	3.82%	-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 2017, the non-regulated portion (before tax adjustment) was $301,080 (2016 - $367,818).

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2015 to 2017.

	Base Salary	Short Term Incentive	Other	Total
2017				
Total executive group	$ 1,271,865	$ 747,000	$ 295,555	$ 2,314,420
Average per executive (4.33)	**$ 293,733**	**$ 172,517**	**$ 68,258**	**$ 534,508**
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**
% Average increase 2017 vs 2016	7.77%	9.21%	30.39%	10.70%
Per executive % average increase 2017 vs 2016	-0.4%	0.88%	16.98%	2.21%

Base salary, for the executive group in 2017 increased from 2016, in addition to general salary increases this overall increase in base salaries is primarily due to the appointment of a new CFO on February 7, 2017 with the previous CFO/COO not appointed to CEO until four months later on June 1st, 2017.

Other compensation for the executive group in 2017 increased from 2016, primarily due to an increase in the performance share unit payout received by each of the executives. STI payouts and performance share unit payouts were agreed to the Board of Directors' minutes.

Company Pension Plan

For 2017, we reviewed the accounts supporting the gross charge of $8,675,000 of pension expense for the Company. A detailed comparison of the components of pension expense for 2015 to 2017 and 2017 test year:

	Actual 2017	Test Year 2017	Actual 2016	Actual 2015	Variance 2017-2016
Pension expense per actuary	**$ 6,165,000**	**$ 4,823,000**	$ 7,330,000	$ 15,332,000	$ (1,165,000)
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**571,000**	**556,000**	557,000	562,000	14,000
Group RRSP @ 1.5%	**321,000**	**347,000**	350,000	384,000	(29,000)
Individual RRSP's	**1,640,000**	**1,906,000**	1,531,000	1,421,000	109,000
Less: Refunds (net of other expenses)	**(22,000)**	**(10,000)**	(5,000)	3,000	(17,000)
Total	**$ 8,675,000**	**$ 7,622,000**	$ 9,763,000	$ 17,702,000	$ (1,088,000)
Year over year percentage change	**(11.14%)**		(44.85%)	33.34%	

Overall, pension expense for 2017 is lower than 2016 primarily due to a decrease in the Company's projected benefit pension obligation. The decrease in obligation was due to a higher than expected return on plan assets, partially offset by a lower discount rate.

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 increased by 2.51% in 2017.

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 7.12% 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 $80,000 in overall RRSP contributions (Group and Individuals) made by the employer in comparison to 2016 primarily reflects wage increases and new hires in the year, which was partially offset by retirements and terminations. The net increase for RRSP expenditures in 2017 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 2015 to 2017 are as follows:

(000's)	Actual 2017	Test Year 2017	Actual 2016	Actual 2015	Variance 2017-2016
Accrued OPEBs	**$ 5,861**	$ 5,652	$ 6,089	$ 6,055	$ (228)
Amortization of transitional balance	**3,504**	3,504	3,504	3,504	-
Amount capitalized	**(1,001)**	(928)	(915)	(906)	(86)
Total	**$ 8,364**	$ 8,228	$ 8,678	$ 8,653	$ (314)

According to the company, the decrease in OPEBs expense from 2016 to 2017 is primarily due to a regulatory amortization that expired in August 2017.

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 2016 to 2017 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2017 and investigated any unusual items;
- vouched a sample of transactions for 2017 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 2015 to 2017 for charges to and from Newfoundland Power Inc.:

	Actual 2017	Actual 2016	Actual 2015	Variance 2017-2016
Charges from related companies				
Regulated	**$ 225,084**	$ 153,602	$ 208,781	$ 71,482
Non-Regulated	**2,143,224**	2,293,715	1,672,009	(150,491)
Total	**$ 2,368,308**	$ 2,447,317	$ 1,880,790	$ (79,009)
Charges to related companies	**$ 2,206,966**	$ 329,339	$ 229,125	$ 1,877,627

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 2017.

- Fortis Inc. estimated its net pool of operating expenses for 2017 based on the 2018-2022 business plan 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.

During the fourth quarter of 2017, a "true up" calculation was completed to reflect actual recoverable expenses which were determined to be $2,002,000 and are summarized as follows:

2017 Recoverable Expenses from Fortis Inc.

	Amount	
Staffing and Staffing Related	$1,204,000	Non-regulated
Director Fees	202,000	Non-regulated
Consulting and Legal fees	111,000	Non-regulated
Trustee Agent Fees	26,000	Regulated
Audit and Other Fees	40,000	Non-regulated
2016 Recovery True Up	8,000	Non-regulated
Annual Meeting Expenses	50,000	Non-regulated
Travel (Board and Other)	67,000	Non-regulated
Insurance (D&O)	35,000	Non-regulated
Other Costs	259,000	Non-regulated
	2,002,000	
Less amounts previously billed:		
Q1 2017	591,000	
Q2 2017	535,000	
Q3 2017	433,000	
Q4 2017 balance owing	$ 443,000	

As detailed above, trustee agent fees for $26,000 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 2015 to 2017 with Fortis Inc.:

Intercompany Transactions

(Regulated)	Actual 2017	Actual 2016	Actual 2015	Variance 2017-2016
Charges from Fortis Inc.				
Trustee fees and share plan costs	**$ 26,000**	$ 33,000	$ 35,000	$ (7,000)
Miscellaneous	**133,361**	53,059	24,472	80,302
Staff Charges	**-**	-	19,756	-
	$159,361	$ 86,059	$ 79,228	$ 73,302
Year over year percentage change	**85.18%**	8.62%	(55.14%)	
Charges to Fortis Inc.				
Printing and stationery	**$ -**	$ -	$ 2,191	$ -
Postage and couriers	**4,113**	7,583	19,468	(3,470)
Staff charges	**43,581**	38,282	44,430	5,299
Staff charges - insurance	**-**	550	4,639	(550)
IS Charges	**5,888**	-	-	5,888
Pole removal and installation	**93**	138	-	(45)
Miscellaneous	**49,406**	16,895	7,855	32,511
	$103,081	$ 63,448	$ 78,583	$ 39,633
Year over year percentage change	**62.47%**	(19.26%)	(54.70%)	

According to Newfoundland Power, regulated charges from Fortis Inc. are generally not based on specific allocation percentages and instead are invoiced based on actual costs or based on Newfoundland Power's usage of a specific service.

The most significant fluctuations from our analysis of regulated charges from Fortis Inc. is an increase in the miscellaneous account of $80,302. This is primarily the result of a one-time SERP payment of $45,577 and a pension expense of $45,531.

The most significant fluctuation from our analysis of regulated charges to Fortis Inc. is a $32,511 increase in the miscellaneous account. This is primarily a result of a Performance Share Unit (PSU) Grant of $30,967.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2015 to 2017:

(Non-Regulated)	**Actual 2017**	**Actual 2016**	**Actual 2015**	**Variance 2017-2016**
Charges from Fortis Inc.				
Director's fees and travel	**202,000**	231,000	166,000	(29,000)
Staff charges	**1,204,000**	1,293,000	944,000	(89,000)
Miscellaneous(i)	**732,811**	769,715	562,009	(36,904)
	$ 2,138,811	$ 2,293,715	$ 1,672,009	$ (154,904)
Charges from Maritime Electric				
Miscellaneous	**$ 4,413**	$ -	**$ -**	$ 4,413
	$2,143,224	$ 2,293,715	$ 1,672,009	$ (150,491)

(i)Miscellaneous includes annual and quarterly report fees.

Staff charges decreased by $89,000, primarily due to a decrease in Newfoundland Power’s percentage allocation of Fortis Inc. corporate costs due to the acquisition of ITC in October 2016, with full year impact experienced in 2017.

Miscellaneous charges from Fortis Inc. decreased by $36,904, primarily due to a decrease in PSU Grant due to a retirement in late 2017.

The following table provides a summary and comparison of the other intercompany transactions for 2015 to 2017:

Intercompany Transactions (Other)	**Actual 2017**	**Actual 2016**	**Actual 2015**	**Variance 2017-2016**
Charges to Fortis Properties				
Staff charges	**$ -**	$ -	$ 23,569	$ -
Staff charges - insurance	**-**	2,950	21,796	(2,950)
Miscellaneous	**-**	-	500	-
	$ -	$ 2,950	$ 45,865	$ (2,950)
Charges from Fortis Properties				
Hotel/Banquet facilities & meals	**$ -**	$ -	$ 3,113	$ -
Miscellaneous	**-**	-	48,885	-
	$ -	$ -	$ 51,998	$ -
Charges to Fortis Ontario Inc.				
Staff charges	**$ 138,200**	$ 22,698	$ 3,620	$ 115,502
Staff charges - insurance	**-**	1,794	5,666	(1,794)
IS charges	**-**	-	4,065	-
Miscellaneous	**1,703**	400	390	1,303
	$ 139,903	$ 24,892	$ 13,741	$ 115,011
Charges to Maritime Electric				
Staff charges	**$ 3,719**	$ 34,749	$ 6,541	$ (31,030)
Staff charges - insurance	**-**	756	934	(756)
IS charges	**-**	-	3,048	-
Miscellaneous	**550**	530	530	20
	$ 4,269	$ 36,035	$ 11,053	$ (31,766)
Charges from Maritime Electric				
Miscellaneous	**16,713**	2,880	250	13,833
Charges from Central Hudson Gas & Electric				
Miscellaneous	**$ 8,034**	$ 3,538	$ 182	$ 4,496

Intercompany Transactions (Other) Cont'd.	Actual 2017	Actual 2016	Actual 2015	Variance 2017-2016
Charges to Belize Electric Company Ltd.				
Staff charges	**$ 112,387**	$ 121,021	$ 20,779	$ (8,634)
Miscellaneous	**845**	1,793	-	(948)
	$ 113,232	**$ 122,814**	**$ 20,779**	$ (9,582)
Charges to FortisAlberta Inc.				
Staff charges - insurance	**$ -**	$ -	$ 39	$ -
Miscellaneous	**4,740**	4,510	4,260	230
	$ 4,740	$ 4,510	$ 4,299	$ 230
Charges from FortisAlberta Inc.				
Miscellaneous	**$ 37,611**	$ 44,744	$ 49,452	$ (7,133)
Charges to FortisBC Inc./ Fortis BC Holdings				
Staff Charges	**$ 11,578**	$ -	$ 39	$ 11,578
IS charges	**-**	-	10,363	-
Miscellaneous	**9,310**	9,240	9,190	70
	$ 20,888	$ 9,240	$ 19,592	$ 11,648
Charges from FortisBC Inc./ FortisBC Holdings				
Miscellaneous	**$ 3,365**	$ 7,359	$ 3,822	$ (3,994)
Charges to Caribbean Utilities Co. Limited				
Staff charges	**$ 4,240**	$ 30,111	$ 22,219	$ (25,871)
Charges from Caribbean Utilities Co. Limited				
Miscellaneous	**$ -**	$ 9,022	$ 23,849	$ (9,022)
Charges to Fortis Turks and Caicos				
Staff charges	**$ 698,896**	$ 32,289	$ 12,271	$ 666,607
Miscellaneous	**1,117,717**	3,050	723	1,114,667
	$ 1,816,613	$ 35,339	$ 12,994	$ 1,781,274

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The most significant fluctuations from our analysis of other intercompany charges for 2017 compared to 2016 are as follows:

- Staff charges to Fortis Ontario Inc. increased by $115,502, primarily due to a NL Power employee's secondment to Fortis Ontario.
- Staff charges to Maritime Electric decreased by $31,030, which reflects the labour and travel time charged to Maritime Electric during the transition period where a new Vice President assumed the position of VP, Customer Service in April 2016 and there were more charges in 2016 related to the transition.
- Staff charges to Caribbean Utilities Co. Limited decreased by $25,871 due to an employee who supplied service pertaining to transportation requirements as well as expenses incurred by an employee who was on the Board of Directors in 2016.
- Staff charges to Fortis Turks and Caicos increased by $666,607, which is a direct result of Newfoundland Power's Hurricane Team's power restoration efforts after Hurricane Irma.
- Miscellaneous Charges to Fortis Turks and Caicos increased by $1,114,667 which is a direct result of Newfoundland Power's Hurricane Team's power restoration efforts after Hurricane Irma. $1,045,954 was for 398 transformers, transformer accessories and freight during restoration efforts, and the remainder was travel expenses, vaccinations and supplies for the Newfoundland Power's Hurricane team.

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 2017 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2017	Actual 2016	Actual 2015	Variance 2017-2016
Other company fees				
Other company fees	$ 3,082	$ 2,092	$ 1,601	$ 990
Regulatory hearing costs	(786)	852	1,156	(1,638)
	$ 2,296	$ 2,944	$ 2,757	$ (648)
Year over year percentage change	-22.0%	6.8%	4.0%	
Deferred regulatory costs				
Total deferred regulatory costs	$ 341	$ 172	$ 322	$ 169
Year over year percentage change	98.3%	-46.6%	0.0%	

Other Company Fee costs for 2017 were lower than 2016. According to the Company, this is due primarily to a reduction in estimated liability for third party costs associated with the investigation by the Public Utilities Board into power outages and supply issues that commenced in 2014 and are ongoing. The variance to 2016 was partially offset by increased consultant costs for customer energy conservation programming, cyber security, and engineering studies. 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 2015 to 2017 is as follows:

(000's)	Actual 2017	Actual 2016	Actual 2015	Variance 2017-2016
Miscellaneous	**$ 1,117**	$ 1,082	$ 967	$ 35
Cafeteria and lunchroom Supplies	**84**	89	84	(5)
Promotional items	**199**	193	152	6
Computer Software	**2**	1	2	1
Damage claims	**216**	196	301	20
Community relations activities	**3**	3	3	-
Donations and charitable advertising	**217**	202	188	15
Books, magazines and subscriptions	**7**	21	35	(14)
Misc. lease payments	**34**	34	33	-
Total miscellaneous expenses	**$ 1,879**	$ 1,821	$ 1,765	$ 58
Year over year percentage change	**3.19%**	3.17%	-10.45%	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2016 to 2017 these expenses have increased by 3.19% overall.

Our procedures in this expense category for 2017 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 2017 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with Order No. P.U. 7 (1996-97), the Company filed the 2017 Conservation and Demand Management Report with the Board. This report provided a summary of 2017 CDM activities and costs as well as the outlook for 2017.

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 Conservation Potential Study through in-depth local market research and program cost benefit analysis.

In 2017, 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) removal of alliance and electronics rebate program; and (iii) ongoing initiatives to educate customers about heat pumps, including a partnership with the government of Newfoundland and Labrador to offer reduced interest financing to eligible customers.

Total CDM costs in 2017 totaled $7,865,000 compared to $8,039,000 in 2016, a $174,000 decrease. Conservation costs are lower than in 2016 as 2016 included increased customer uptake on instant rebates for items offering energy savings such as LED light bulbs.

In 2017, $6,758,000 ($4,731,000 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 2017 and 2016.

(000's)	Actual 2017	Actual 2016	Actual 2015	Variance 2017-2016
Vehicle expense	1,854	1,797	1,786	57
Operating materials	1,528	1,425	1,583	103
Inter-company charges	2,002	2,145	1,560	(143)
Plants, Subs, System Oper & Bldgs	2,796	2,770	2,367	26
Travel	1,235	1,160	1,052	75
Tools and clothing allowance	1,234	1,161	1,130	73
Conservation	2,981	4,253	2,466	(1,272)
Taxes and assessments	1,252	1,214	1,123	38
Uncollectible bills	1,386	1,194	1,313	192
Insurance	1,326	1,293	1,260	33
Severance & other employee costs	102	47	72	55
Education, training, employee fees	339	275	298	64
Trustee and directors' fees	489	471	426	18
Stationary & copying	214	266	230	(52)
Equipment rental/maintenance	806	838	746	(32)
Communications	2,927	2,959	3,184	(32)
Advertising	1,592	1,519	1,251	73
Vegetation management	2,099	1,820	1,766	279
Computing equipment & software	1,451	1,359	1,058	92
Transfers (GEC)	(2,847)	(2,955)	(3,809)	108
CDM amortization	2,741	1,712	1,053	1,029

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

- Conservation costs in 2017 were lower than 2016 as 2016 included customer uptake of customer energy conservation incentives instant rebate campaign.
- Uncollectible bills were higher in 2017 than 2016 reflecting higher AR balances.
- Vegetation management costs for 2017 were higher than 2016 due to increased vegetation management activity for distribution, transmission lines, and substations reflecting favorable weather conditions.
- Amortization of Deferred CDM costs commenced in 2014 and is higher in 2017 due to the inclusion of the fourth year of deferred customer energy conservation programming costs.

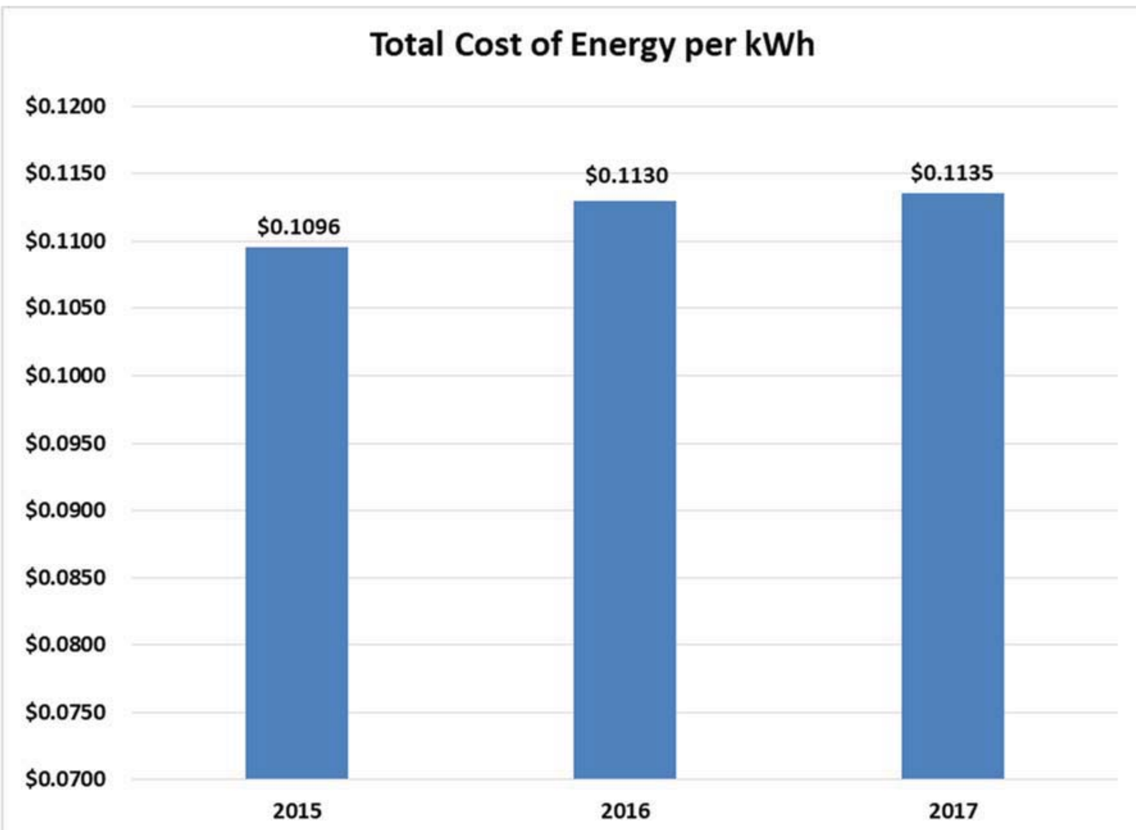
Other Costs

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 2015 to 2017:

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
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
2017	5,922,200	$ 80,472	$ 440,249	$ (1,032)	$ 62,973	$ 35,365	$ 12,882	$ 41,526	$ 672,435	$ 0.1135



Purchased Power

We have reviewed the Company's purchased power expense for 2017 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 decreased by $3.1 million, from $443.3 million in 2016 to $440.2 million in 2017. According to the Company, the decrease in costs were lower in 2017 due to lower energy purchases partially offset by higher demand charges from Hydro.

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 2017 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 2017; and,
- assessed the overall reasonableness of the depreciation for 2017.

Amortization expense for 2017 is $62,973,000 as compared to $60,472,000 for 2016, representing a 4.1% increase. The 2017 and 2016 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)	**2017**	**2016**	**Variance 2017-2016**	**%**
Depreciation and amortization as reported	$ 62,973	$ 60,472	$ 2,501	**4.1%**
Less: Tax on Cost of Removal (1)	(5,486)	(5,282)	(204)	**3.9%**
Depreciation of Fixed Assets	$ 57,487	$ 55,190	$ 2,297	**4.2%**

Note 1: Recognized as income tax for financial reporting purposes

The following table provides a comparison of the depreciation of fixed assets for 2017, 2016 and 2015:

($000's)	**2017**	**2016**	**2015**	**Variance 2017-2016**	**Variance 2016-2015**
Depreciation of Fixed Assets	$ 57,487	$ 55,190	$ 51,851	$ 2,297	$ 3,339

Depreciation of fixed assets for 2017 is $57,487,000 as compared to $55,190,000 for 2016, representing a 4.2% increase. The change is attributable to an increase of depreciable assets by approximately $63,366,000.

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 2017.

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 2015 to 2017:

(000's)	Actual 2017	Actual 2016	Acutal 2015	Variance 2017-2016
Interest				
Long-term debt	**$ 35,013**	$ 34,846	$ 35,020	167
Other	**672**	878	1,139	(206)
Amortization				
Debt discount	**234**	223	242	11
Interest charged to construction	**(554)**	(712)	(677)	158
Total Finance charges	**$ 35,365**	$ 35,235	$ 35,724	130
Year over year percentage change	**0.37%**	-1.37%	-1.99%	

In the above table, finance charges increased by approximately $0.13 million, from $35.2 million in 2016 to $35.4 million in 2017. According to the company, the increase was due to the combination of (i) interest costs associated with the issuance of $75 million, 3.815% first mortgage sinking fund bonds in June 2017, (ii) the maturity of $30.4 million, 10.9% first mortgage sinking fund bonds in May 2016, and (iii) lower facility borrowings.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2017 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 22.6% in 2016 to 23.7% in 2017. 2017 and 2016 results in the following effective rates:

	2017	2016	2015	2017-2016
Income tax expense	$ 12,882	$ 11,851	$ 10,925	$ 1,031
Earnings before income tax	$ 54,408	$ 52,359	$ 50,239	$ 2,049
Effective income tax rate	23.7%	22.6%	21.7%	1.1%

Income tax expense increased by $1,031,000 compared to 2016. The increase is due to higher pre-tax earnings and an increase in the effective tax rate from 22.6% to 23.7%. The statutory tax rate was 30.0% for both 2017 and 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 2017 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 $424,674 for the current period compare to a total of $349,974 for the same period during the previous year. The credit total for the 2016-2017 winter season is higher than the previous season total primarily due to higher contracted load curtailment. There were 23 option participants in 2016-2017, compared to 18 participants in the previous year.

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 2017 to prior years and investigated any unusual fluctuations;
* reviewed detailed listings of expenses for 2017 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 2017	Actual 2016	Actual 2015		Variance 2017-2016
Charged from Fortis Companies	**2,121,500**	2,249,100	1,672,000		(127,600)
Performance and restricted share units	**687,500**	454,500	276,800		233,000
Donations and charitable advertising	**301,700**	283,300	273,700		18,400
Executive short term incentive	**361,900**	341,000	272,600		20,900
Miscellaneous	**45,000**	70,200	39,100		(25,200)
	3,517,600	3,398,100	2,534,200	-	119,500
Less: Income Taxes	**1,055,300**	1,019,400	734,900		35,900
Total non-regulated (net of tax)	**$ 2,462,300**	**$ 2,378,700**	**$ 1,799,300**		$ 83,600

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 2017 this represents an addition to non-regulated expenses (before tax adjustment) of $361,900 (2016 - $341,000). 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 2017 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 2016 and 2017:

(000's)	2017 Actual	2016 Actual	Variance 2017-2016
Regulatory Assets			
Rate stabilization account	**$ 4,519**	$ 4,763	$ (244)
OPEBs asset	**28,032**	31,536	(3,504)
Deferred GRA costs	**341**	682	(341)
Conservation and demand management deferral	**20,017**	15,999	4,018
Demand management incentive	**2,128**	-	2,128
Employee future benefits	**82,732**	100,757	(18,025)
Weather normalization account	**6,815**	2,458	4,357
Deferred income taxes	**207,207**	191,313	15,894
	$ 351,791	$ 347,508	$ 4,283
Regulatory Liabilities			
Rate stabilization account	**$ 4,254**	$ -	4,254
Cost recovery deferral	**1,032**	2,064	(1,032)
Future removal and site restoration provision	**151,975**	143,419	8,556
	$ 157,261	$ 145,483	$ 11,778

<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, 2017 were approved by the Board in Order No. P.U. 23 (2017).

As of December 31, 2017, there was a charge to the RSA of $7,292,557 related to the Energy Supply Cost Variance Reserve in accordance with Order No. P.U. 32 (2007) and Order No. P.U. 43 (2009), and the Wholesale Rate Change Flow-Through Account approved in Order No. P.U. 23 (2017).

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, 2017, the credit balance of $114,060 in the OPEBVDA account was transferred to the RSA.

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, 2017, the balance of $1,167,213 in the PEVDA account was credited to the RSA.

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, 2017 $2,458,149 was credited 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 therefore no impact on RSA in 2017) 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 $341,000 incurred in 2017.

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, 2017 were $20,017,000 with amortization of $2,740,556 in 2017.

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, 2017 the regulated asset for employee future benefits was $82,732,000.

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. 11 (2018) the Board approved the December 31, 2017 net regulatory asset balance in the Weather Normalization Account of $6,815,000 ($4,770,830 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, 2017 was $207,207,000.

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 accumulated amortization of $1,548,000 over 2016 and 2017, resulting in a net regulating liability of $1,032,000 as at December 31, 2017.

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 2017 the balance in this account was $151,975,000 (2016 - $143,419,000).

Based upon our analysis, nothing has come to our attention to indicate that changes in regulatory deferrals for 2017 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 2017 PEVDA was calculated at $1,167,213. This balance was transferred to the Rate Stabilization Account as a charge on March 31, 2017 in accordance with Order No. P.U. 43 (2009).

We confirm that the 2017 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 2017 OPEBVDA was calculated at $114,060. This balance was transferred to the Rate Stabilization Account as a charge on March 31, 2017 in accordance with Order No. P.U. 31 (2010).

We confirm that the 2017 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 2017 are as follows:

1. Made capital investments of $91 million of which over 57% 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 installation of Automated Meter Reading (AMR) meters was substantially complete by year end. In 2017, the company has installed over 44,000 meters and reduced a total of 152 routes through optimization. Implementation of AMR meters has allowed the company to realize significant operating efficiencies in customer metering. Over the 5 years ending in 2017, annual meter reading operating costs per customer have been reduced by approximately 2/3rds from $12.56 to $4.16.

5. Continued the Substation Modernization and Refurbishment program. In total 87% of the distribution feeders are now automated.

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

7. An email promotion conducted in the 4th quarter resulted in an additional 2,259 new accounts being enrolled in the e-bills program. Over 113,000 customers were enrolled in e-Bills at year-end. This represents approximately 44% of all billed customers.

8. Newfoundland Power and the Provincial Department of Environment and Climate Change finalized a more streamlined blanket permitting system. The new consolidated permit ensures that day to day operations are within environmental guidelines and cover topics such as fording bodies of water, protected public water supply areas and pole placements near water bodies.

9. A new phone call handling technology was implemented in the Customer Contact Centre. The new system from Avaya is performing as intended and has enabled a number of improvements to call forecasting and staff scheduling. It was effective in supporting response to a high volume of calls within an hour of its implementation on May 1, when over 21,000 customers were left without power following a loss of supply from Hydro. In the 3rd quarter, enhancements will include implementation of an email management module.

10. In September, the company implemented an improved process for handling customer emails within the Customer Contact Centre. The Avaya system now permits Customer Service Representatives to switch from customer telephone response to email response directly within a single software application. This technological refinement enables Customer Service Representatives to more efficiently respond to customers.

11. Installed remote computer terminals at Corner Brook and Burin offices which allow customers to directly talk to a CSR in St. John's and Clarenville.

12. Upgraded mobile maintenance inspection application and integrated it with the Company's GIS system.

Performance Measures

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

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

The following table lists the principal performance measures used in the management as provided by the company.

Category	Measure	Actual 2015	Actual 2016	Actual 2017	Plan 2017	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1]	2.36	2.24	2.28	2.30	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply[1]	2.11	1.36	1.66	1.87	Yes
	Plant Availability (%)[2]	94.9	85.3	91.3	96.0	No
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	86.0	86.0	86.5	87.0	No
	Call Centre Service Level (% per second)	82/60	81/60[4]	80/60	80/60	Yes
	Trouble Call Responded to Within 2 Hours (%)	86.0	87.0	87.0	85.0	Yes
Safety	All Injury/Illness Frequency Rate	0.5	1.3	0.7	0.9	Yes
Financial	Earnings (millions)[3]	$38.8	$40.0	$41.0	$39.1	Yes
	Gross Operating Cost/Customer[3]	$249	$260	$264	$269	Yes

[1]2016 reliability statistics exclude the impact of a wind storm in December. 2017 reliability statistics exclude the impact of a snow storm in December and a snow storm in March.
[2] Includes total hours of plant availability. Q4 Regulatory Report excludes the hours the generation unit is out of service due to system disruptions and major plant refurbishment.
[3]Excludes Pension, OPEBs and early retirement costs.
[4] 82/60 per Q4 Quarterly Regulatory Report. Difference does not impact whether the measure was achieved in 2016.

The following table compares whether the company measures were achieved during the 2015, 2016, and 2017 years:

Category	Measure	Measure Achieved 2015	Measure Achieved 2016	Measure Achieved 2017
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply	Yes	Yes	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply	No	Yes	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 (%)	Yes	Yes	Yes
Safety	All Injury/Illness Frequency Rate	Yes	No	Yes
Financial	Earnings (millions)	Yes	Yes	Yes
	Gross Operating Cost/Customer	Yes	Yes	Yes