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Board of Commissioners of Public Utilities

Financial Consultants Report
2019 Annual Financial Review of
Newfoundland Power Inc.

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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 2019 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 Access to Information and Protection of Privacy Act 2015 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 2019 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 2019 was $1,153,556,000 which is an increase of $36,215,000 (3.24%) over the average rate base for 2018 of $1,117,341,000. The Company's calculation of the return on average rate base for 2019 was 6.97% (2018 – 7.13%) compared to an approved rate of return of 7.01%. The actual rate of return was within the range approved by the Board (6.83% to 7.19%). 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 2019 was $510,388,000 (2018 - $495,374,000). The Company's actual return on average common equity for the year ended December 31, 2019 was 8.79% (2018 – 8.76%). 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, the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2019 the cost of common equity was 8.50% as per Order No. P.U. 2 (2019). The actual return on average common equity for 2019 was 8.79% 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 2.5% over budget in 2019. The capital expenditures were over the approved budget (including projects carried over from prior years) on a net basis by $6,145,000 (5.21%). However, for each category of expenditure, the variances ranged from an over-budget of 55.08% to an under-budget of 100.00%.

The Company experienced a 3.39% increase in revenue from rates in 2019 as compared to 2018. The increase is primarily due to the flow through of higher wholesale electricity rates effective July 1, 2018. This increase is offset due to lower electricity sales of 29.5 GWh compared to 2018 due to lower average consumption by residential customers.

Overall, net operating expenses decreased by $3,379,000 from 2018 to 2019. 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 2019 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 2019 Pension Expense Variance Deferral Account (PEVDA) operated in accordance with Order No. P.U. 43 (2009).

Based on our review, the 2019 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 2019 the Company met seven out of nine of its planned performance measures. The Company fell short of its targets in "Call Centre Service Level" and "Trouble Call Responded to Within 2 Hours".

Introduction

This report to the Board of Commissioners of Public Utilities presents our observations, findings and recommendations with respect to our 2019 Annual Financial Review of Newfoundland Power Inc.

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;
   - amortization of regulatory costs;
   - 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, and
   - travel.

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 2019 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 2014 Depreciation Study 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, 2019 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 12, 2020. 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 27, 2020, the Company filed a revised system of accounts as part of its 2019 Annual Report. In submitting these changes, the Company noted that the revisions were mainly due to the addition of three new accounts and some minor wording changes to improve the clarity and accuracy of account descriptions.

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, 2019 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 2019 was $1,153,556,000 which is an increase of $36,215,000 (3.24%) over the average rate base for 2018 of $1,117,341,000. 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 2019; 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 2018 and 2019 (all figures shown are averages):

(000)'s	2019	2018
Net Plant Investment (average)		
Plant Investment	$1,909,493	$1,834,415
Accumulated Depreciation	(771,588)	(739,030)
CIAC's	(41,596)	(38,474)
	1,096,309	1,056,911
Additions to Rate Base (average)		
Deferred Charges (a)	90,842	90,963
Cost Recovery Deferral for Hearing Costs (b)	247	171
Cost Recovery Deferral – Conservation (c)	16,630	15,003
Customer Finance Programs (d)	2,477	1,978
Demand Management Incentive Account (e)	941	745
Weather Normalization Reserve (f)	3,586	3,144
	114,723	112,004
Deductions from Rate Base (average)		
Other Post-Employment Benefits (g)	59,452	54,848
Customer Security Deposits (h)	1,245	1,069
Accrued Pension Obligation (i)	5,060	5,294
Deferred Income Taxes (j)	7,488	4,401
Cost Recovery Deferral (k)	613	362
	73,858	65,974
Average Rate Base before Allowances	1,137,174	1,102,941
Rate Base Allowances		
Materials and Supplies	6,475	6,184
Cash Working Capital	9,907	8,216
	16,382	14,400
Average Rate Base	$1,153,556	$1,117,341

(a) The Company's rate base is determined using the ARBM which incorporates average deferred charges into the calculation of rate base. The total average deferred charges of $90,842,000 (2018 - $90,963,000) included in the 2019 rate base consists of average deferred pension costs of $90,751,000 (2018 - $90,848,000) and credit facility costs of $91,000 (2018 - $115,000). The Company has included a schedule of these costs in Return 8.

(b) In Order No. P.U. 2 (2019) the Board approved the 34-month amortization of $1,000,000 in estimated hearing costs related to the 2019/2020 General Rate Application, commencing March 1, 2019 through December 31, 2021. According to the Company, the actual hearing costs for the 2019/2020 General Rate Application were $329,728. The Company transferred $670,272 to the Rate Stabilization Account on March 31, 2019 representing the difference between actual of $329,728 and estimated costs of $1,000,000 as directed by the Board in Order No. P.U. 2 (2019) instead of a reduction in rate base in 2019. The 2019 average rate base includes an addition of $247,000 relating to these hearing costs.

(c) 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. The actual costs incurred and deferred in 2018 were $6,239,000 ($4,367,000 after tax) resulting in additional annual amortization of $624,000 to commence in 2019. The actual costs incurred and deferred in 2019 were $6,864,000 ($4,805,000 after tax) resulting in additional annual amortization of $686,000 to commence in 2020. Included in the calculation of the average rate base for 2019 is $16,630,000 (2018 - $15,003,000) related to this deferral.

(d) Customer Finance Programs are comprised of loans provided to customers related to customer conservation programs and contributions in aid of construction. The 2019 average rate base incorporates $2,477,000 (2018 - $1,978,000) related to these programs.

(e) The 2018 balance of the Demand Incentive Account was $Nil as there was no supply cost variance outside the dead band. In Order No P.U. 11 (2020) the Board approved the disposition of the 2019 balance of the Demand Incentive Account of $2,687,000 ($1,881,000 after tax) by means of a debit to the Rate Stabilization Account as of March 31, 2020. The 2019 average rate base incorporates $941,000 (2018 - $745,000) related to this account.

(f) During 2019, 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 $1,517,000 in 2019 (2018 – $4,771,000 increase).

Other transfers:

i. $1,347,000 transfer decrease (2018 – $90,000 decrease) to the reserve related to the after tax impact of the Degree Day Normalization Reserve Transfer.
ii. $4,307,000 transfer decrease (2018 - $1,427,000 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 $4,137,000 (2018 - $3,254,000 decrease). The ending balance in this reserve account totaled ($5,654,000) compared to a balance of ($1,517,000) at December 31, 2018 (an average of ($3,586,000) for 2019) (2018 – ($3,144,000)). This represents a balance to be recovered from customers.

(g) Other Post-Employment Benefits is equal to the difference, at December 31, 2019, between the OPEBs liability of $92,026,000 and the OPEBs asset of $30,235,000. The calculation of the 2019 average rate base of $59,452,000 is equal to the average of the December 31, 2019 net liability of $61,791,000 and the December 31, 2018 net liability of $57,112,000.

(h) 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 2019 average rate base incorporates $1,245,000 (2018 - $1,069,000) related to customer security deposits.

(i) The 2019 average rate base calculation incorporates $5,060,000 (2018 - $5,294,000) 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.

(j) 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 2019 average rate base is ($2,954,000) and ($15,636,000) respectively. The remaining balance of the deferred income tax liability in the amount of $26,078,000 relates to capital assets. This results in an average balance for deferred income tax liability of $7,488,000 (2018 - $4,401,000).

(k) In Order No. P.U. 2 (2019) the Board approved the deferral over a 34-month period of a $2,482,000 (before tax) over-recovery of revenue from March 1, 2019 rate implementation of rates. The 2019 average rate base includes deduction of $613,000 (2018 - $362,000).

The net change in the Company's average rate base from 2018 to 2019 can be summarized as follows:

(000's)	**2019**	2018
Average rate base - opening balance	**$ 1,117,341**	$ 1,092,254
Change in average deferred charges and deferred regulatory costs	**1,332**	139
Average change in:		
Plant in service	**75,078**	61,539
Accumulated depreciation	**(32,558)**	(29,045)
Contributions in aid of construction	**(3,122)**	(1,241)
Weather normalization reserve	**442**	(102)
Other post-employment benefits	**(4,604)**	(5,515)
Future income taxes	**(3,087)**	(1,351)
Rate base allowances	**1,982**	110
Customer Finance Programs	**499**	559
Demand Management Incentive Acct	**196**	-
Other rate base components (net)	**57**	(6)
Average rate base - ending balance	**$ 1,153,556**	$ 1,117,341

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2019 average rate base, and therefore conclude that the 2019 average rate base included in the Company's annual report to the Board is 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 2019 was 6.97% (2018 – 7.13%). 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 2019, the return on average rate base is calculated in accordance with the methodology approved in Order No. P.U. 2 (2019).

The actual return on average rate base in comparison to the range of allowed return for each of the years from 2017 to 2019 is set out in the table below.

	2019	2018	2017
Actual Return on Average Rate Base	6.97%	7.13%	7.22%
Upper End of Range set by the Board	7.19%	7.22%	7.37%
Lower End of Range set by the Board	6.83%	6.86%	7.01%

The Board approved the Company's rate of return on average rate base of 7.01% in a range of 6.83% to 7.19% for 2019 in Order No. P.U. 2 (2019). As noted above, the Company's actual return on average rate base for 2019 was 6.97% which was inside the range set by the Board.

The actual rate of return for 2018 was within the range set by the Board.

The actual rate of return for 2017 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. 2 (2019) the Board reconfirmed its previous position as per Order No. P.U. 18 (2016) 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 2019 as reported in Return 24 is as follows:

	2019 Average		**2018**	**2017**
	(000's)	**Percent**	Percent	Percent
Debt	**$ 616,343**	**54.28%**	54.53%	54.22%
Preferred equity	**8,880**	**0.78%**	0.80%	0.82%
Common equity	**510,388**	**44.94%**	44.67%	44.96%
	$ 1,135,611	**100%**	100%	100%

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 2019 test year in Return 26. The embedded cost of debt for 2019 was 6.00% which represents a 7 bps decrease from the 2018 embedded cost of debt of 6.07%.

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. 2 (2019).

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, 2019 is included on Return 27 of the annual report to the Board. The average common equity for 2019 was $510,388,000 (2018 - $495,374,000). The Company's actual return on average common equity for 2019 was 8.79% (2018 – 8.76%).

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), Order No. P.U. 18 (2016), and Order No. P.U. 2 (2019); and
- recalculated the rate of return on common equity for 2019 and ensured it was in accordance with established practice, Order No. P.U. 32 (2007) and Order No. P.U. 2 (2019).

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, the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2019 the cost of common equity was 8.50% as per Order No. P.U. 2 (2019). The actual return on average common equity for 2019 was 8.79% 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)	2019	2018	2017
Net Income	**$42,891**	$41,744	$41,526
Income Taxes	**11,299**	12,280	12,882
Interest on long term debt	**35,375**	35,788	35,013
Interest during construction	**(1,933)**	(951)	(1,025)
Other interest and amortization of discount costs	**1,590**	931	893
Total	**$89,222**	$89,792	$89,289
Interest on long term debt	**$35,375**	$35,788	$35,013
Other interest and amortization of discount costs	**1,590**	931	893
Total	**$36,965**	$36,719	$35,906
Interest Coverage (times)	**2.4**	2.4	2.5

The above table shows that the interest coverage had not changed from 2018 to 2019.

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 2019 is 2.4 times.

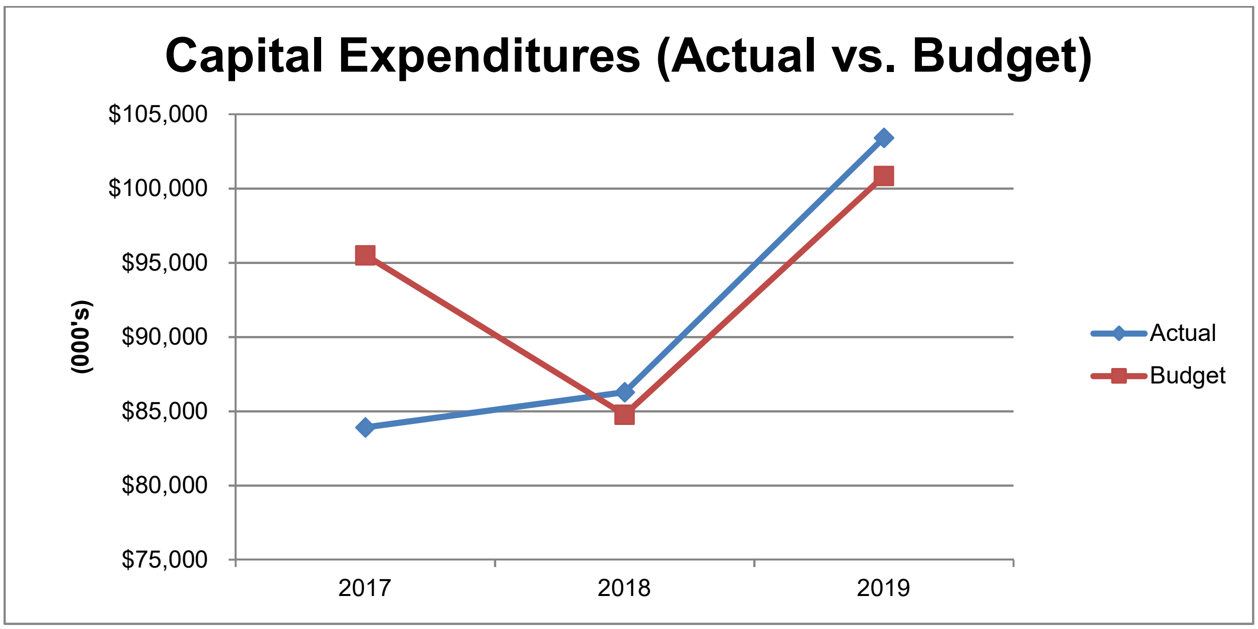
Capital Expenditures

Scope: ***Review the Company's 2019 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 2017 to 2019:

($000's)	**2017**	**2018**	**2019**	**Notes**
Actual	$ 83,921	$ 86,285	$ 103,417	**1**
Budget	$ 95,521	$ 84,776	$ 100,856	
Over (under) budget	(12.14%)	1.78%	2.54%	

Note 1: Total expenditures per the 2019 Capital Budget report includes the carryover amount of $2,879,000 for a total of $106,296,000. The carryover amount is made up of five projects included in the following categories; $150,000 to generation; $310,000 to transmission; $530,000 to renovations; $1,575,000 to transportation; and $314,000 to information systems. According to the Company, these expenditures will occur in 2020.



The following table provides a summary of the capital expenditure activity in 2019 as reported in the Company's *"2019 Capital Expenditure Report":*

($000's)	Capital Budget			Actual Expenditures		
	Prior Years	2019	Total	Prior Years	2019	Total
2019 Capital Projects (1)	$ -	$ 100,856	$100,856	$ -	$103,417	$103,417
2018 Projects Carried to 2019 & Multi Year Projects:						
Facility Rehabilitation (2)	2,119	-	2,119	2,348	253	2,601
Purchase Mobile Generation	6,000	-	6,000	4,453	1,595	6,048
Rebuild Transmission Lines	5,068	-	5,068	5,027	-	5,027
Duffy Place Roof Replacement (3)	900	-	900	402	699	1,101
System Upgrades	245	-	245	201	-	201
Outage Management System Replacement	2,360	-	2,360	1,758	602	2,360
Human Resource Management System Replacement	422	-	422	481	-	481
	17,114	-	17,114	14,670	3,149	17,819
Grand Total	**$ 17,114**	**$ 100,856**	**$ 117,970**	**$ 14,670**	**$106,566**	**$121,236**

(1) Approved by Order P.U. 35 (2018), P.U. 5 (2019), P.U. 6 (2019) and P.U. 36 (2019).

(2) The Company has noted that the unfavorable budget variance arose from the Second Storage Pond Dam refurbishment project and the Tors Cove Access Road Bridge Replacement project as additional fill material and larger concrete abutments were required due to poor foundation conditions found during excavation. Additional costs were also incurred on the Rocky Pond Turbine Bearing Replacement project due to alignment issues encountered when the generator was reassembled.

(3) The Company has noted that the unfavorable budget variance of the Duffy Place Roof Replacement project arose as a result of deteriorated roof conditions resulting in persistent leaks in 2017 and 2018. Additional expenses were also incurred from this project due to added difficulties experienced when replacing the roof under winter conditions.

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

($000's)	2019 Budget (1)	2019 Actuals (2)	Variance	Carryover (3)	Variance Including Carryover	%
Generation - Hydro	$ 4,782	$ 5,211	$ 429	$ -	$ 429	8.97%
Generation - Thermal	14,242	13,344	(898)	150	(748)	(5.25%)
Substation	19,731	17,133	(2,598)	-	(2,598)	(13.17%)
Transmission	16,559	16,582	23	310	333	2.01%
Distribution	40,151	46,801	6,650	-	6,650	16.56%
General property	3,530	3,420	(110)	530	420	11.90%
Transportation	3,990	2,648	(1,342)	1,575	233	5.84%
Telecommunications	233	312	79	-	79	33.91%
Information systems	10,002	9,582	(420)	314	(106)	(1.06%)
Unforeseen	750	-	(750)	-	(750)	(100.00%)
General expenses capitalized **(4)**	4,000	6,203	2,203	-	2,203	55.08%
Total	**$ 117,970**	**$ 121,236**	**$ 3,266**	**$ 2,879**	**$ 6,145**	**5.21%**

1. Includes prior years projects and current year budgeted amounts as there were projects incomplete at the previous year ends.
2. 2019 actuals include the total expense for projects carried forward from 2018.
3. Represents $2,879,000 of capital projects carried forward to 2020.
4. The increase in General Expenses Capitalized over budget resulted from a change in the capitalization of pension expense associated with Accounting Standards Update 2017-07. This change was approved in Order No. P.U. 2 (2019) and was not included in the original budget for this project according to the company.

As indicated in the table, actual capital expenditures were higher than the approved budget by $3,266,000 (2.77%) and when carryover amounts are taken into account, they were $6,145,000 (5.21%) higher. However, for each category of expenditure, the variances ranged from an over-budget of 55.08% for the General expenses capitalized category to an under-budget of 100.00% for the Unforeseen 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)
Purchase Mobile Generation	$ 150
Transmission Line 114L Relocation at Customer Request	310
Company Building Renovations	530
Purchase Vehicles and Aerial Devices	1,575
System Upgrades	95
Cybersecurity Upgrades	146
Human Resource Management System Replacement	73
Total Carryover	**$ 2,879**

The Company has provided detailed explanations on budget to actual variances in its “2019 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 2019 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 its explanations of variances greater than both $100,000 and 10%; and

- 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 1.78% in 2018 and 2.54% in 2019 resulting in no additional reporting requirements.

The allowance for unforeseen items account was not utilized in 2019.

<u>Capital Expenditure Reports</u>

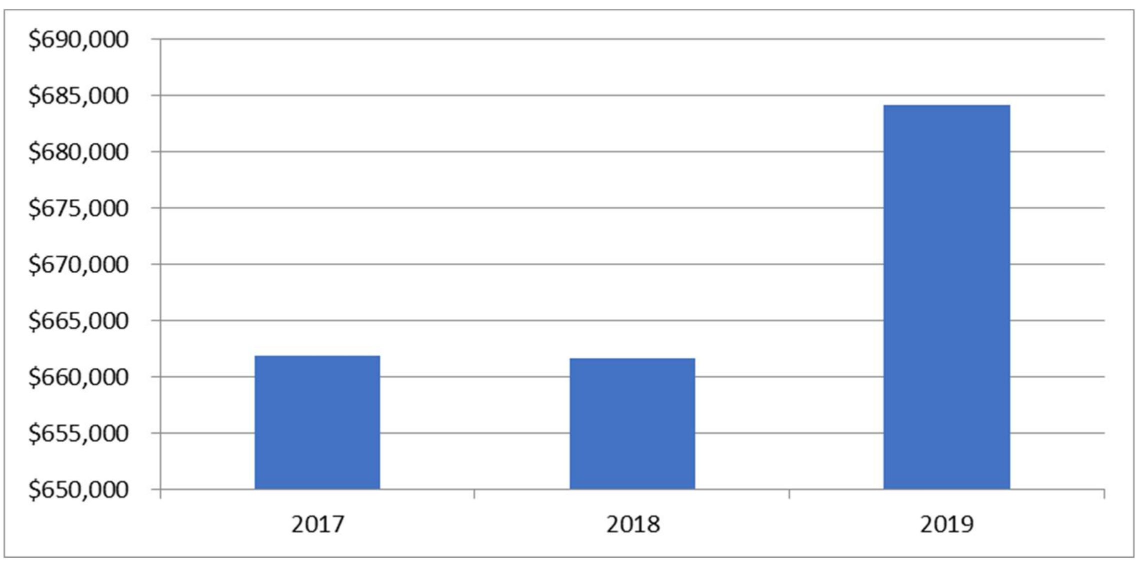
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2019 calendar year.

Revenue from rates

Scope: ***Review the Company's 2019 revenue from rates in comparison to prior years and follow up on any significant variances.***

We have compared the actual revenues from rates for 2017 to 2019 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

($000's)	2017	2018	2019
Residential	$ 422,237	$ 419,389	$ 432,272
General Service			
0-100 kW	88,507	90,364	93,038
110-1000 kVA	95,565	97,338	101,397
Over 1000 kVA	37,099	35,725	37,916
Streetlighting	16,149	16,255	16,664
Discounts forfeited	2,327	2,643	2,892
Revenue from rates	$ 661,884	$ 661,714	$ 684,179
Year over year percentage change	0.08%	(0.03%)	3.39%



The above graph demonstrates that the Company has seen a 3.39% increase in revenue from rates in 2019 as compared to 2018. The increase is primarily due to higher wholesale electricity rates effective July 1, 2018. These factors were partially offset by the impact of lower electricity sales.

The comparison by rate class of 2019 actual revenues to 2019 budget is as follows:

($000's)	2018	2019	2019 Plan	Actual - Plan Variance	%
Residential	$ 419,389	$ 432,272	$ 425,007	$ 7,265	1.71%
General Service					
0-100 kW	90,364	93,038	90,815	2,223	2.45%
110-1000 kVA	97,338	101,397	99,525	1,872	1.88%
Over 1000 kVA	35,725	37,916	37,721	195	0.52%
Streetlighting	16,255	16,664	16,410	254	1.55%
Discounts forfeited	2,643	2,892	2,587	305	11.79%
Total revenue from rates	$ 661,714	$ 684,179	$ 672,065	$ 12,114	1.80%

We have also compared the 2019 budget energy sales in GWh to the actual sold in 2019:

	2018	2019	2019 Plan	Actual - Plan Variance	%
Residential	3,593.0	3,559.8	3,586.6	(26.8)	(0.75%)
General Service					
0-100 kW	805.4	797.6	792.5	5.1	0.64%
110-1000 kVA	1,022.9	1,024.6	1,031.8	(7.2)	(0.70%)
Over 1000 kVA	422.0	432.0	445.3	(13.3)	(3.08%)
Streetlighting	32.8	33.0	32.8	0.2	0.61%
Total	5,876.1	5,847.0	5,889.0	(42.0)	(0.72%)

Actual 2019 revenue from rates was higher than 2019 Plan with an overall increase in actual sales of $12,114,000 (1.80%) from the 2019 Plan due to increased rates as of October 1, 2019. There was a 0.72% decrease in GWh sold in 2019 compared to 2019 Plan primarily due to the lower average consumption by residential and commercial customers as a result of the overall economic climate in the province. The largest variance in revenue can be seen in the Residential, 0 – 100 kW class, and the 110 – 1000 kVA class where revenues increased by $7,265,000 (1.71%), $2,223,000 (2.45%), and $1,872,000 (1.88%), 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.***

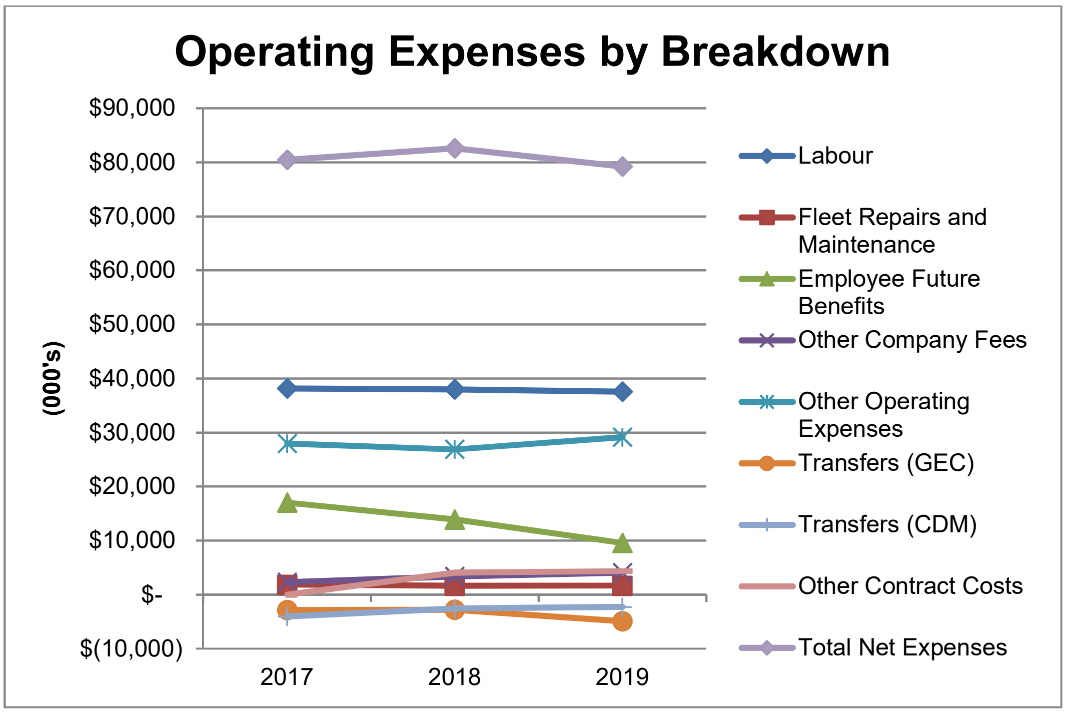
(000's)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Labour	$ 38,603	$ 39,095	$ 39,341	$ (492)
Reclass OPEB labour cost	(1,041)	(1,125)	(1,173)	84
Total Labour	37,562	37,970	38,168	(408)
Vehicle expense	1,681	1,682	1,854	(1)
Operating materials	1,361	1,511	1,528	(150)
Inter-company charges	2,058	1,847	2,002	211
Plants, Subs, System Oper & Bldgs	3,267	2,812	2,796	455
Travel	1,142	1,127	1,235	15
Tools and clothing allowance	1,289	1,254	1,234	35
Miscellaneous	2,005	1,619	1,879	386
Conservation	2,813	2,732	2,981	81
Taxes and assessments	1,156	1,286	1,252	(130)
Uncollectible bills	1,980	1,490	1,386	490
Insurance	1,397	1,306	1,326	91
Severance & other employee costs	132	68	102	64
Education, training, employee fees	444	403	339	41
Trustee and directors' fees	518	481	489	37
Other company fees	4,058	3,379	2,296	679
Stationary & copying	257	224	214	33
Equipment rental/maintenance	790	784	806	6
Communications	2,803	2,822	2,927	(19)
Advertising	1,581	1,443	1,592	138
Vegetation management	2,042	1,692	2,099	350
Computing equipment & software	1,830	1,628	1,451	202
Total Other	34,604	31,590	31,788	3,014
Pension & early retirement program	3,335	7,726	8,675	(4,391)
OPEB's	6,241	6,194	8,364	47
Total employee future benefits	9,576	13,920	17,039	(4,344)
Total gross expenses	81,742	83,480	86,995	(1,738)
Transfers (GEC)	(4,913)	(2,781)	(2,847)	(2,132)
CDM amortization	4,597	3,706	2,741	891
Other contract expenses	4,353	4,081	-	272
Deferred CDM program costs	(6,864)	(6,239)	(6,758)	(625)
Deferred regulatory costs	294	341	341	(47)
Total net expenses	**$ 79,209**	**$ 82,588**	**$ 80,472**	**$ (3,379)**

The above table provides details of operating and general expenses (including non-regulated expenses) by "breakdown" for 2017, 2018, and 2019.

Overall, net operating expenses decreased by $3,379,000 from 2018 to 2019. 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 2019 are unreasonable.

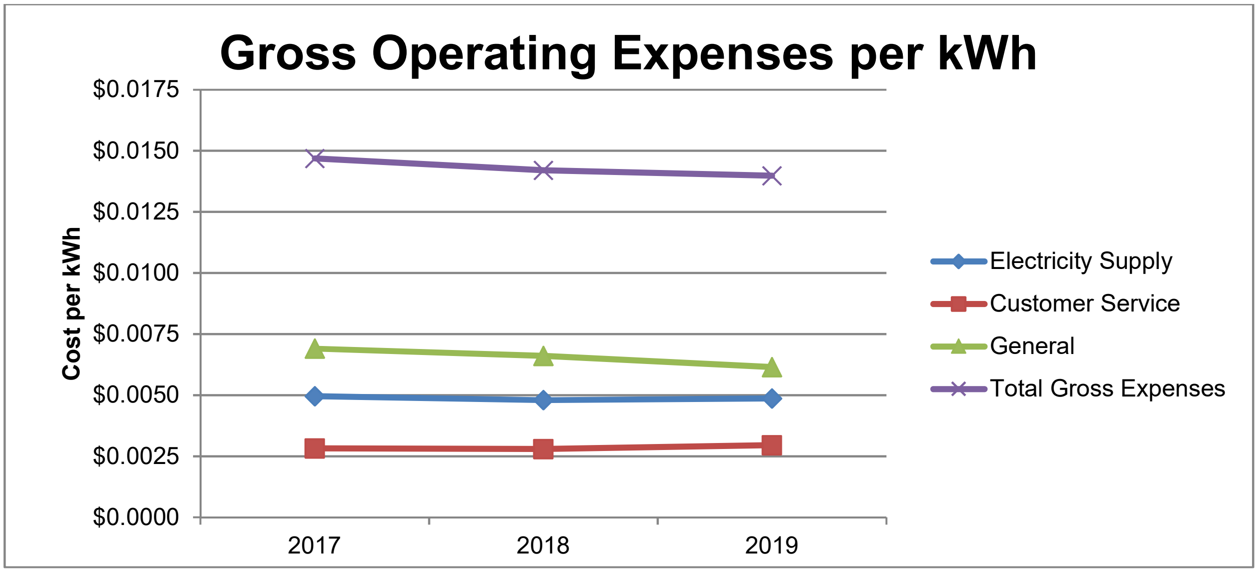
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph show the trend in operating expenses by breakdown for the period 2017 to 2019.

	Actual		
(000's)	**2017**	**2018**	**2019**
Labour	$ 38,168	$ 37,970	$ 37,562
Fleet Repairs and Maintenance	1,854	1,682	1,681
Employee Future Benefits	17,039	13,920	9,576
Other Company Fees	2,296	3,379	4,058
Other Operating Expenses	27,979	26,870	29,159
Transfers (GEC)	(2,847)	(2,781)	(4,913)
Transfers (CDM)	(4,017)	(2,533)	(2,267)
Other Contract Costs	-	4,081	4,353
Total Net Expenses	**$ 80,472**	**$ 82,588**	**$ 79,209**



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2017 to 2019 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
2017	5,922,200	$29,352	$0.0050	$16,754	$0.0028	$40,889	$0.0069	$86,995	$0.0147
2018	5,876,100	$28,185	$0.0048	$16,429	$0.0028	$38,866	$0.0066	$83,480	$0.0142
2019	5,846,600	$28,473	$0.0049	$17,298	$0.0030	$35,971	$0.0062	$81,742	$0.0140



The table and graph show that total gross expenses per kWh have decreased by approximately 1.4% compared to 2018.

There was a decrease in General Costs of $2.9 million, with increases in Customer Service Costs of $0.9 million and in Electricity Supply Costs of $0.3 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 2017 to 2019 (including 2019 plan) is as follows:

	Actual 2019	**Plan 2019**	Actual 2018	Actual 2017	**Actual - Plan**	**Actual 2019-2018**
Executive Group	**6.2**	**6.0**	5.7	6.3	0.2	0.5
Corporate Office	**20.8**	**20.0**	19.8	20.0	0.8	1.0
Finance and IT	**93.5**	**91.6**	91.6	88.9	1.9	1.9
Engineering and Operations	**383.2**	**385.2**	372.9	365.4	(2.0)	10.3
Customer Relations	**72.8**	**69.1**	78.8	84.3	3.7	(6.0)
	576.5	**571.9**	568.8	564.9	4.6	7.7
Temporary employees	**39.7**	**52.3**	50.4	46.3	(12.6)	(10.7)
Total	**616.2**	**624.2**	619.2	611.2	(8.0)	(3.0)

The overall number of FTE's in 2019 compared to 2018 decreased by 3. The budgeted number of FTEs in the 2019 Plan was 624.2 versus actual of 616.2. The variances between 2019, 2019 Plan and 2018 are the result of the following:

- Finance and Information Technology is higher than plan due to a shift from temporary employees and timing of planned hires. Additionally, the increase from 2018 is due to increased labour for the Customer Information System ("CIS") Assessment project;
- Engineering and operations is consistent with plan. However, the increase over 2018 is due to a shift in metering positions from Customer Relations and increased labour for capital distribution work;
- Customer relations is higher than plan due to a shift from temporary employees. The decrease from 2018 is primarily due to lower labour for metering services and meter reading, a reallocation of metering positions to Engineering & Operations, and timing of planned hours; and
- Temporary Employees is lower than plan and 2018 primarily due to a shift from temporary to regular employees and timing of planned hours.

An analysis of salaries and wages by type of labour and by function from 2017 to 2019 is as follows:

(000's)	**Actual 2019**	Actual 2018	Actual 2017	**Variance 2019-2018**
Type				
Internal labour	**$ 66,023**	$ 65,090	$ 64,399	$ 933
Overtime	**6,568**	6,568	6,807	-
	72,591	71,658	71,206	933
Contractors	**17,523**	15,409	12,883	2,114
	$ 90,114	$ 87,067	$ 84,089	$ 3,047
Function				
Operating	**$ 38,603**	$ 39,095	$ 39,341	$ (492)
Capital and miscellaneous	**51,511**	47,972	44,748	3,539
Total	**$ 90,114**	$ 87,067	$ 84,089	$ 3,047
Year over year percentage change	**3.50%**	3.54%	6.27%	

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 2019 were $3,047,000 (3.50%) higher than 2018.

Internal labour costs in 2019 were higher than 2018 due to normal labour inflation and increased labour for capital distribution work, increased labour for the CIS Assessment project and the Human Resource Management System. This increase was largely offset by lower corporate costs and reduced labour for metering services, meter reading and timing of planned hires.

Contract labour for 2019 was higher than 2018 due to increased labour for transmission rebuilds and third party work for telecommunication companies.

Capital and miscellaneous labour for 2019 was higher than 2018 due to increased labour for capital distribution work, transmission rebuilds, third party work for telecommunication companies, and inflationary increases.

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 2017 to 2019 are included in the table below:

Salary Cost Per FTE

	Actual 2019	Actual 2018	Actual 2017	**Variance 2019-2018**
Total reported internal labour costs	**$ 66,023**	$ 65,090	$ 64,399	$ 933
Benefit costs (net)	**(8,926)**	(8,939)	(8,960)	13
Other adjustments	**(1,126)**	(725)	(1,171)	(401)
Base salary costs	**55,971**	55,426	54,268	545
Less: executive compensation	**(1,938)**	(1,693)	(2,016)	(245)
Base salary costs (excluding executive)	**$ 54,033**	$ 53,733	$ 52,252	$ 300
FTE's (including executive members)	**616.2**	619.2	611.2	
FTE's (excluding executive members)	**612.2**	615.5	606.9	
Average salary per FTE	**90,833**	89,512	88,789	
% increase	**1.48%**	0.81%	3.62%	
Average salary per FTE (excluding executive members)	**88,261**	87,300	86,097	
% increase	**1.10%**	1.40%	3.39%	

The above analysis indicates that the rate of increase in average salary per FTE excluding executive members for 2019 has decreased from 2018, and 2018 decreased from 2017.

Newfoundland Power has two collective agreements governing its union employees represented by the International Brotherhood of Electrical Workers, Local 1620 (the “IBEW”). Negotiated wage increases in the collective agreements included a 2.5% increase on January 1st, 2017. In addition, new collective agreements for both were signed on May 6, 2019, and included the wage increases outlined below over the term of the contracts.

	Oct. 1, 2017	Jan. 1, 2019	Jan. 1, 2020	Jan. 1, 2021	Jan. 1, 2022
Craft	1.0%	1.50%	2.00%	2.00%	2.25%
Clerical	1.0%	1.50%	2.00%	2.00%	2.25%

These negotiated wage increases were applied retroactively to October 1, 2017, i.e. 2.5% January 1, 2017 and 1% October 1, 2017. Timing of the wage increases and retroactive amounts are the primary reason for the lower level of percentage increase from 2017 to 2019 for the average salary per FTE (excluding executive members).

Short Term Incentive (STI) Program

The following table outlines the actual results for 2017 to 2019 and the targets set for 2019:

Measure	Target 2019	Actual 2019	Actual 2018	Actual 2017
Controllable Operating Costs/Customer	**$ 232.70**	$ 231.00	$ 225.10	$ 228.80
Earnings	**$ 40.9M**	$ 42.3M	$ 41.2M	$ 41.0M
Cash Flow from Operating Activities	**$ 108.9M**	$ 111.2M	$ -	$ -
Reliability - Duration of Outages (SAIDI)	**2.39**	2.34	2.65	2.28
Customer Satisfaction - % Satisfied	**85.6%**	85.8%	85.6%	86.5%
Injury Frequency Rate	**0.92**	0.37	-	0.18
Regulatory Performance	**-**	-	150%	120%

2019 STI results were adjusted to remove the impact of the severe weather conditions in February, September and November. In 2019 the ‘regulatory performance’ measure was replaced by the ‘cash flow from operating activities’ measure.

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 2019 is established as a percentage of base pay for the three employee groups. For 2019, all six measures above were met.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2017 to 2019:

	Target 2019	Actual 2019	Target 2018	Actual 2018	Target 2017	Actual 2017
President	50%	70.00%	50%	60.30%	50%	66.32%
Executive	35% - 40%	50.42%	35% - 40%	47.04%	40%	57.28%
Directors	15%	17.94%	15%	18.28%	15%	20.03%

STI actual payout rates for ‘President’, ‘Executive’ and ‘Director’ employee groups are higher than the prior year and each payout rate exceeded targets consistent with 2018 and 2017.

In dollar terms, the STI payouts for 2017 to 2019 are as follows:

		Actual 2019		Actual 2018		Actual 2017		Variance 2019-2018
President	**$**	**287,000**	$	230,000	$	240,396	$	57,000
Executive		**416,000**		346,000		506,604		70,000
Directors		**311,000**		296,200		332,999		14,800
Total	**$**	**1,014,000**	$	872,200	$	1,079,999	$	141,800
Year over Year % change		**16.26%**		-19.24%		7.22%		

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 2019, the non-regulated portion (before tax adjustment) was $344,832 (2018 - $262,753).

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2017 to 2019:

		Base Salary		Short Term Incentive		Other		Total
2019								
Total executive group	$	1,235,000	$	703,000	$	421,412	$	2,359,412
Average per executive (4)	**$**	**308,750**	**$**	**175,750**	**$**	**105,353**	**$**	**589,853**
2018								
Total executive group	$	1,116,648	$	576,000	$	630,311	$	2,322,959
Average per executive (3.74)	**$**	**298,569**	**$**	**154,011**	**$**	**168,532**	**$**	**621,112**
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**
% Average change 2019 vs 2018		10.60%		22.05%		(33.14%)		1.57%
Per executive % average change 2019 vs 2018		3.41%		14.12%		(37.50%)		(5.03%)

Base salary for the executive group in 2019 increased from 2018 primarily due to the increase in FTE for executives which in 2019 was 4 FTE compared 3.74 FTE in 2018. In 2019, four executives held positions for the entire year resulting in 4 FTE. This increase compared to 2018 is due to the fact that in 2018 there were changes in executive positions, including the appointment of a new CEO effective June 1, 2018 and the new executive position of Vice President, Energy Supply and Planning effective September 1, 2018.

Other compensation for the executive group in 2019 decreased from 2018, primarily due to a vacation payout for an executive in 2018. STI payouts and performance share unit payouts were agreed to the Board of Directors' minutes.

Company Pension Plan

For 2019, we reviewed the accounts supporting the gross charge of $3,335,000 of pension expense for the Company. A detailed comparison of the components of pension expense for 2017 to 2019 is below:

	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Pension expense per actuary	**$ 639,000**	$ 5,163,000	$ 6,165,000	$ (4,524,000)
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**347,000**	501,000	571,000	(154,000)
Group RRSP @ 2%[1]	**315,000**	289,000	321,000	26,000
Individual RRSP's	**2,055,000**	1,790,000	1,640,000	265,000
Less: Refunds (net of other expenses)	**(21,000)**	(17,000)	(22,000)	(4,000)
Total	**$ 3,335,000**	$ 7,726,000	$ 8,675,000	$ (4,391,000)
Year over year percentage change	**(56.83%)**	(10.94%)	(11.14%)	

Note 1: Plan amendment which increased the contribution rate from 1.5% to 2.0% as of May 2019.

Overall, pension expense for 2019 is lower than 2018 primarily due to lower current service costs and lower amortization of net actuarial losses as a result of an increase in the 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 decreased by 30.74% in 2019.

The employer's portion of the contributions to the Group RRSP is calculated as 2.0% (increased to 2% as of May 2019) of the base salary paid to the plan participants. Individual RRSP contributions increased as a result of a plan amendment which increased the contribution rate for the 5.75% plan to 6.25% as of May 2019. New hires are added to the Individual RRSP Plan whereas the majority of retirements are out of the Group RRSP Plan. The increase in Group RRSP contributions made by the employer was primarily the result of a plan amendment which increased the contribution rate from 1.5% to 2.0% as of May 2019, which was partially offset by retirements.

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 2017 to 2019 are as follows:

(000's)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Accrued OPEBs	**$ 3,657**	$ 3,648	$ 5,861	$ 9
Amortization of transitional balance	**3,504**	3,504	3,504	-
Amount capitalized	**(920)**	(958)	(1,001)	38
Total	**$ 6,241**	$ 6,194	$ 8,364	$ 47

According to the Company, the decrease in OPEBs expense after 2017 is primarily due to a lower benefit obligation resulting from the 2017 OPEB valuation and the expiry of a regulatory amortization in August 2017.

Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with P.U. 19 (2003), P.U. 32 (2007), P.U. 43 (2009), and P.U. 13 (2013);
- compared intercompany charges for the years 2018 to 2019 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2019 and investigated any unusual items;
- vouched a sample of transactions for 2019 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 2017 to 2019 for charges to and from Newfoundland Power Inc.:

	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Charges from related companies				
Regulated	**$ 339,937**	$ 1,121,634	$ 225,084	$ (781,697)
Non-Regulated	**2,360,484**	2,101,634	2,143,224	258,850
Total	**$ 2,700,421**	$ 3,223,268	$ 2,368,308	$ (522,847)
Charges to related companies	**$ 1,214,048**	$ 643,394	$ 2,206,966	$ 570,654

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 and noted during our review that Fortis Inc. continues to allocate its recoverable costs based on its subsidiaries' assets. There were no significant changes to the methodology in 2019.

- Fortis Inc. estimated its net pool of operating expenses for 2019 based on the 2019-2023 business plan and is billed quarterly.
- On a quarterly basis, these expenses are subject to a true-up based on actual expenses incurred during the quarter with any true-up applied in the subsequent quarter.

During the fourth quarter of 2019, a “true-up” calculation was completed to reflect actual recoverable expenses which were determined to be $2,058,000 and are summarized as follows:

2019 Recoverable Expenses from Fortis Inc.

	Amount	
Staffing and Staffing Related	$1,332,000	Non-regulated
Director Fees and Travel	178,000	Non-regulated
Consulting and Legal fees	129,000	Non-regulated
Trustee Agent Fees	27,000	Regulated
Audit and Other Fees	44,000	Non-regulated
2018 Recovery True Up	(8,000)	Non-regulated
2019 True Up	(38,000)	Non-regulated
Annual Meeting Expenses	43,000	Non-regulated
Insurance (D&O)	44,000	Non-regulated
Other Costs	307,000	Non-regulated
	2,058,000	
Less amounts previously billed:		
Q1 2019	708,000	
Q2 2019	555,000	
Q3 2019	440,000	
Q4 2019 balance owing	$ 355,000	

As detailed above, trustee agent fees for $27,000 were the only expenses allocated to regulated operations by the Company relating to recoverable expenses. According to the Company, regulated charges from Fortis Inc. to Newfoundland Power are generally not based on specific allocation percentages rather charges are invoiced based on actual costs or based on Newfoundland Power’s usage of a specific service. There were additional invoices of $579,133 received directly from Fortis during 2019 for total Fortis charges of $2,637,133 (2,058,000+579,133), of which $276,649 were regulated and $2,360,484 were non-regulated. These 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 2017 to 2019 with Fortis Inc.:

	Actual	Actual	Actual	Variance
(Regulated)	**2019**	**2018**	**2017**	**2019-2018**
Charges from Fortis Inc.				
Trustee fees and share plan costs	**$ 27,000**	$ 25,000	$ 26,000	$ 2,000
Miscellaneous	**208,765**	941,488	133,361	(732,723)
Staff Charges	**40,884**	92,711	-	(51,827)
	$ 276,649	$ 1,059,199	$ 159,361	$ (782,550)
Year over year percentage change	**(73.88%)**	564.65%	85.18%	
Charges to Fortis Inc.				
Postage and couriers	**$ 2,181**	$ 3,165	$ 4,113	$ (984)
Staff charges	**51,573**	27,471	43,581	24,102
IS Charges	**-**	-	5,888	-
Pole removal and installation	**-**	-	93	-
Miscellaneous	**31,561**	97,880	49,406	(66,319)
	$ 85,315	$ 128,516	$ 103,081	$ (43,201)
Year over year percentage change	**(33.62%)**	24.67%	62.47%	

The most significant fluctuations from our analysis of regulated charges from Fortis Inc. is a decrease in the miscellaneous account of $732,723 and a decrease in staff charges of $51,827. These fluctuations are primarily due to the pay out of SERP costs of $817,115 for a former CEO who retired January 1, 2018 and an employee on secondment from Fortis Inc., respectively.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2017 to 2019:

(Non-Regulated)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Charges from Fortis Inc.				
Director's fees and travel	**$ 178,000**	$ 139,000	$ 202,000	$ 39,000
Staff charges	**1,294,000**	1,054,000	1,204,000	240,000
Miscellaneous	**888,484**	908,634	732,811	(20,150)
	$ 2,360,484	$ 2,101,634	$ 2,138,811	$ 258,850
Charges from Maritime Electric				
Miscellaneous	**$ -**	$ -	$ 4,413	$ -
	$ 2,360,484	$ 2,101,634	$ 2,143,224	$ 258,850

Director's fees and travel increased by $39,000 primarily due to the Director's Share Unit expense. Otherwise, director's fees and travel stayed relatively consistent. There are a variety of factors that influence the Director's Share Unit expense, such as the number of active directors and the units outstanding. However, the main factors causing the increase include an increase in dividend rates from 2018 to 2019 resulting in more units outstanding, and more share price growth assumed in 2019 than in 2018.

Staff charges have increased from 2018 by $240,000 primarily due to the change in share based compensation. In addition to higher units outstanding for share based plans, 2019 saw a large increase in the share price relative to 2018 which leads to higher overall expense recognition.

Miscellaneous charges decreased by $20,150 due to a variety of factors. According to the Company, the most significant trend this year is that while spending levels increased for 2019, more spending was determined to be non-recoverable from subsidiaries, resulting in lower billing to Newfoundland Power for 2019 compared to 2018. Non-recoverable amounts are amounts incurred at Fortis Inc. that do not benefit the subsidiaries such as business development projects and donations. During 2019, a higher portion of costs were related to these types of projects, resulting in the lower allocation to subsidiaries.

The following table provides a summary and comparison of the other intercompany transactions for 2017 to 2019:

Intercompany Transactions (Other)	Actual 2019	Actual 2018	Actual 2017	Variances 2019-2018
Charges to Fortis Ontario Inc.				
Staff charges	**$ 390,837**	$ 371,640	$ 138,200	$ 19,197
Miscellaneous	**326,592**	35,193	1,703	291,399
	$ 717,429	$ 406,833	$ 139,903	$ 310,596
Charges from Fortis Ontario Inc.				
Miscellaneous	**$ 4,875**	$ -	$ -	$ 4,875
Charges to Maritime Electric				
Staff charges	**$ 276,106**	$ -	$ 3,719	$ 276,106
Miscellaneous	**78,496**	550	550	77,946
	$ 354,602	$ 550	$ 4,269	$ 354,052
Charges from Maritime Electric				
Miscellaneous	**$ 6,193**	$ 15,258	$ 16,713	$ (9,065)
Charges to Central Hudson Gas & Electric				
Staff charges	**$ 6,321**	$ -	$ -	$ 6,321
Charges from Central Hudson Gas & Electric				
Miscellaneous	**$ 10,190**	$ 5,705	$ 8,034	$ 4,485

Intercompany Transactions (Other) Cont'd.	Actual 2019	Actual 2018	Actual 2017	Variances 2019-2018
Charges to Belize Electric Company Ltd.				
Staff charges	**$ 35,226**	$ 91,553	$ 112,387	$ (56,327)
Miscellaneous	**475**	-	845	475
	$ 35,701	$ 91,553	$ 113,232	$ (55,852)
Charges to FortisAlberta Inc.				
Miscellaneous	**$ 5,000**	$ 4,980	$ 4,740	$ 20
Charges from FortisAlberta Inc.				
Miscellaneous	**$ 37,612**	$ 38,073	$ 37,611	$ (461)
Charges to FortisBC Inc./ FortisBC Holdings				
Staff Charges	**$ -**	$ -	$ 11,578	$ -
Miscellaneous	**9,680**	9,370	9,310	310
	$ 9,680	$ 9,370	$ 20,888	$ 310
Charges from FortisBC Inc./ Fortis BC Holdings				
Miscellaneous	**$ 4,418**	$ 3,399	$ 3,365	$ 1,019
Charges to Caribbean Utilities Co. Limited				
Staff charges	**$ -**	$ -	$ 4,240	$ -
Charges to Fortis Turks and Caicos				
Staff charges	**$ -**	$ -	$ 698,896	$ -
Miscellaneous	**-**	1,592	1,117,717	(1,592)
	$ -	$ 1,592	$1,816,613	$ (1,592)

The most significant fluctuations from our analysis of other intercompany charges for 2019 compared to 2018 are as follows:

- Staff charges to Belize Electric Company Ltd. decreased by $56,327 primarily due to decreases in technical support requirements compared to 2018;
- Miscellaneous charges to Fortis Ontario Inc. increased by $291,399 primarily due to an employee's 2018 short term incentive payments amounting to $156,200 and another charge to refund the company for $163,200 for the same employee ($319,400); and
- Staff charges and miscellaneous charges to Maritime Electric have increased by $276,106 and $77,946 respectively as the 2019 year included charges relating to Hurricane Dorian.

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

Lender	Maximum Amount Borrowed	Date Borrowed	Date Repaid	Interest Rate	Total Interest Cost [1]
Fortis Inc.	$ 75,000,000	June 20, 2019	August 29, 2019	2.39625%	$ 253,244
Fortis Inc.	20,000,000	August 20, 2019	August 29, 2019	2.39125%	11,792
Fortis Inc.	60,000,000	December 20, 2019	On Demand[2]	2.47875%[3]	44,821
	$ 155,000,000				$ 309,857

1. Interest charged by Fortis is based on its credit facility, less a discount of 36bps.
2. On December 31, 2019, Newfoundland Power re-paid $9,500,000 plus $44,821 interest.
3. Interest rate was reset on January 20, 2020.

The interest rates charged on each of the loans above were lower than what would have been charged under the Company's debt facilities. Fortis Inc. provides Newfoundland Power with an interest discount of 36bps which is equal to the standby fee of 16bps and a direct Fortis discount of 20bps.

In Order No. P.U. 19 (2003), the Board provided instructions to the Company with respect to the recording and reporting of intercompany transactions. Some of these instructions required reports to be filed with the Board at various times in 2019. Confirmation was received from the Board that quarterly reports relating to intercompany transactions have been filed for 2019.

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 2019 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Other company fees				
Other company fees	**$ 3,746**	$ 2,855	$ 3,082	$ 891
Regulatory hearing costs	**312**	524	(786)	(212)
	$ 4,058	$ 3,379	$ 2,296	$ 679
Year over year percentage change	**20.1%**	47.2%	(22.0%)	
Deferred regulatory costs				
Total deferred regulatory costs	**$ 294**	$ 341	$ 341	$ (47)
Year over year percentage change	**(13.8%)**	0.0%	98.3%	

Other Company Fee costs for 2019 were higher than 2018. According to the Company, this is primarily due to higher consultant costs for customer energy conservation programs, CIS Assessment project and dam safety reviews partially offset by lower consultant costs for regulatory activity. Deferred regulatory costs are discussed in the section of the report relating to regulatory assets and liabilities.

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

Miscellaneous

The breakdown of items included in the miscellaneous expense category for 2017 to 2019 is as follows:

(000's)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Miscellaneous	**$ 1,231**	$ 994	$ 1,117	$ 237
Cafeteria and lunchroom Supplies	**75**	77	84	(2)
Promotional items	**169**	137	199	32
Computer Software	**3**	10	2	(7)
Damage claims	**278**	174	216	104
Community relations activities	**1**	2	3	(1)
Donations and charitable advertising	**195**	183	217	12
Books, magazines and subscriptions	**18**	7	7	11
Miscellaneous lease payments	**35**	35	34	-
Total miscellaneous expenses	**$ 2,005**	$ 1,619	$ 1,879	$ 386
Year over year percentage change	**23.84%**	(13.84%)	3.19%	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2018 to 2019 these expenses have increased by 23.84% overall. According to the Company, miscellaneous costs for 2019 were higher than 2018 due to increased damage claims, adjustments to materials and supplies, and customer energy conservation education and outreach costs.

Our procedures in this expense category for 2019 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 2019 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with Order No. P.U. 7 (1996-97), the Company filed the 2019 Conservation and Demand Management Report with the Board. This report provided a summary of 2019 CDM activities and costs as well as the outlook for 2020.

In 2015, Newfoundland and Labrador Hydro and Newfoundland Power (“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 2019, the Utilities continued to implement the 2016 Plan. These activities include: the development of new educational resources for business; extending the take CHARGE Insulation and Thermostat Rebate Programs to oil heat customers in partnership with the government of Newfoundland and Labrador and the Government of Canada; continuing delivery of the Instant Rebates program; and launching a heat pump load research study.

CDM costs in 2019 totaled $7,772,000 compared to $7,252,000 in 2018, a $520,000 increase. Conservation costs are higher than in 2018 due to increased costs associated with head pump load research.

In 2019, $6,864,000 ($4,805,000 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.

General Expense Capitalized (GEC)

($000's)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Transfers (GEC)	**(4,913)**	(2,781)	(2,847)	(2,132)

The capitalization of pension costs has been reflected through the Company's General Expenses Capitalized ("GEC") account based on the GEC methodology approved by the Board in Order No. P.U. 3 (1995-96). In that Order, it was noted that Newfoundland Power was the only utility that included pension costs in a GEC allocation. In the Company's report to the Board, dated August 14, 2020, titled "Review of Capitalization Policies and Guidelines" it was noted by the Company that its practice of capitalizing pension in GEC or capitalized overhead is not common among Canadian utilities. It was also noted in the report that ten of the eleven respondents to a survey capitalize pension costs by means of a labour loader.

In Order No. P.U. 2 (2019) the Board approved the Company's proposal to increase the allocation of pension costs to GEC from 11% to 46%, to comply with Accounting Standards Update 2017-07 – *Improving the Presentation of Net Periodic Pension Costs and Net Periodic Post-Retirement Benefit Cost*, issued in March 2017 by the Financial Accounting Standards Board (the "Update"). This Update provided guidance that the amount of current service pension cost capitalized should reflect the proportion of labour costs that are related to capital work. Utilities that capitalize pension costs using a labour loader would already follow the proportion of labour costs that are related to capital work and therefore would not have been impacted by this Update.

Transfers to GEC for 2019 were higher than 2018 due to the increase in the capitalization percentage of current service pension costs as noted above.

Other Operating 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 2019 and 2018.

($000's)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Vehicle expense	**1,681**	1,682	1,854	(1)
Operating materials	**1,361**	1,511	1,528	(150)
Inter-company charges	**2,058**	1,847	2,002	211
Plants, Subs, System Oper & Bldgs	**3,267**	2,812	2,796	455
Travel	**1,142**	1,127	1,235	15
Tools and clothing allowance	**1,289**	1,254	1,234	35
Conservation	**2,813**	2,732	2,981	81
Taxes and assessments	**1,156**	1,286	1,252	(130)
Uncollectible bills	**1,980**	1,490	1,386	490
Insurance	**1,397**	1,306	1,326	91
Severance & other employee costs	**132**	68	102	64
Education, training, employee fees	**444**	403	339	41
Trustee and directors' fees	**518**	481	489	37
Stationary & copying	**257**	224	214	33
Equipment rental/maintenance	**790**	784	806	6
Communications	**2,803**	2,822	2,927	(19)
Advertising	**1,581**	1,443	1,592	138
Vegetation management	**2,042**	1,692	2,099	350
Computing equipment & software	**1,830**	1,628	1,451	202
CDM amortization	**4,597**	3,706	2,741	891

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

1. Inter-company charges were higher in 2019 than in 2018 due to higher recoveries charged by Fortis;
2. Plants, Subs, System Oper And Bldgs costs for 2019 were higher than 2018 due to increased building repair and maintenance costs and higher generation taxes;
3. Uncollectible bills for 2019 were higher than 2018 reflecting a decline in general economic conditions;
4. Vegetation management costs for 2019 were higher than 2018 due to increased vegetation management activity for distribution;
5. Amortization of Deferred CDM costs commenced in 2014 and is higher in 2019 due to the inclusion of the sixth year of deferred customer energy conservation programming costs.

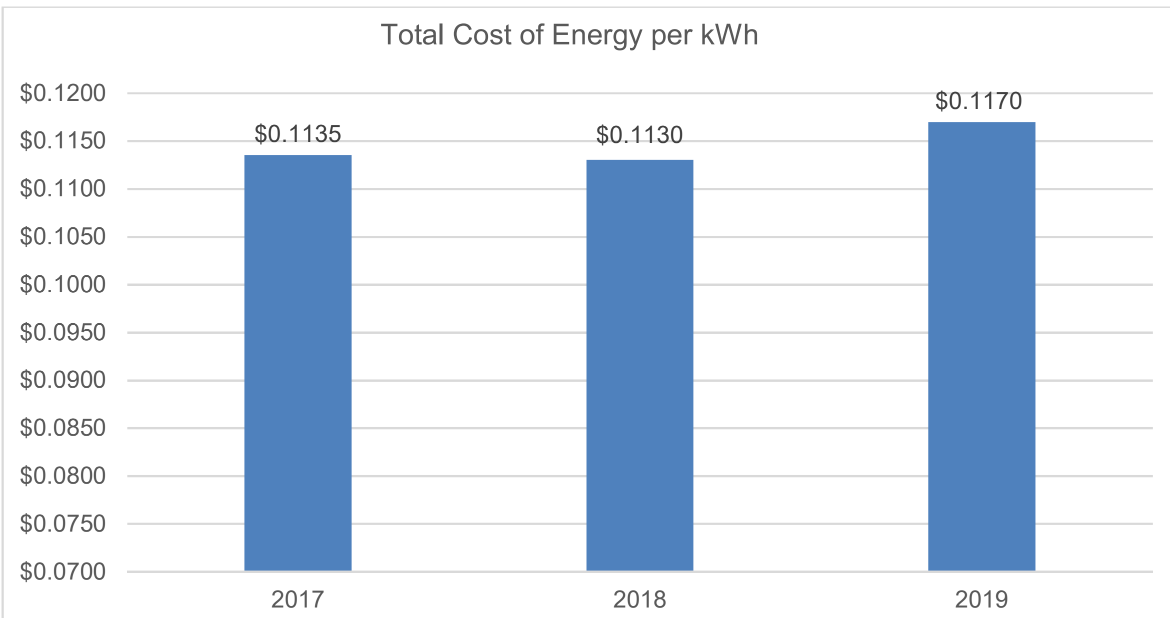
Other Costs

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 2017 to 2019:

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
2017	5,922,200	$ 80,472	$ 440,249	$ (1,032)	$ 62,973	$ 35,365	$ 12,882	$ 41,526	$672,435	$ 0.1135
2018	5,876,100	$ 82,588	$ 427,219	$ (1,032)	$ 65,170	$ 36,212	$ 12,280	$ 41,744	$664,181	$ 0.1130
2019	5,846,600	$ 79,209	$ 444,861	$ 1,752	$ 68,019	$ 35,931	$ 11,299	$ 42,891	$683,962	$ 0.1170



Purchased Power

We have reviewed the Company's purchased power expense for 2019 and have investigated the reasons for any fluctuations and changes. We performed a recalculation of the purchased power to ensure that the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro is consistent with the established rates provided and found no errors.

Purchased power expense increased by $17.6 million, from $427.2 million in 2018 to $444.9 million in 2019. According to the Company, the costs were higher in 2019 primarily due to an increase in wholesale electricity rates effective July 1, 2018. We also noted that the company experienced an increase in wholesale electricity rates effective October 1, 2019 as approved in Order No. P.U. 30 (2019).

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 2019 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 2019; and
- assessed the overall reasonableness of the depreciation for 2019.

Amortization expense for 2019 is $68,019,000 as compared to $65,170,000 for 2018, representing a 4.4% increase. The 2019 and 2018 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)	2019	2018	Variance 2019-2018	%
Depreciation and amortization as reported	**$ 68,019**	$ 65,170	$ 2,849	4.4%
Less: Tax on Cost of Removal (1)	**(5,953)**	(5,704)	(249)	4.4%
Depreciation of Fixed Assets	**$ 62,066**	$ 59,466	$ 2,600	4.4%

Note 1: Recognized as a reduction in income tax for financial reporting purposes.

The following table provides a comparison of the depreciation of fixed assets for 2019, 2018 and 2017:

(000's)	2019	2018	2017	Variance 2019-2018	Variance 2018-2017
Depreciation of Fixed Assets	**$ 62,066**	$ 59,466	$ 57,487	$ 2,600	$ 1,979

Depreciation of fixed assets for 2019 is $62,066,000 as compared to $59,466,000 for 2018, representing a 4.4% increase. The change is attributable to an increase of depreciable assets by approximately $90,430,000.

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), Order No. P.U. 18 (2016), and Order No. P.U. 2 (2019). 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 2019.

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 2017 to 2019:

(000's)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Interest				
Long-term debt	**$ 35,375**	$ 35,788	$ 35,013	$ (413)
Other	**1,384**	712	672	672
Amortization				
Debt discount	**235**	235	234	-
Interest charged to construction	**(1,063)**	(523)	(554)	(540)
Total Finance charges	**$ 35,931**	$ 36,212	$ 35,365	$ (281)
Year over year percentage change	**(0.78%)**	2.40%	0.37%	

There has been little change in total finance charges as the Company incurred a slight decrease from $36.2 million in 2018 to $35.9 million in 2019. From this analysis and explanations provided by the Company, the following observations were made with respect to the more significant fluctuations:

1. Other interest was higher due to short term borrowings due primarily to the financing of the 2019 Capital program; and
2. Interest charged to construction was higher due to a number of larger capital projects including the build and purchase of a new mobile gas turbine and larger IT projects such as Human Resources Information Systems (HRIS).

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2019 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2019 and have noted that the effective income tax rate decreased from 22.7% in 2018 to 20.9% in 2019. 2019 and 2018 results in the following effective rates:

	2019	2018	2017	2019-2018
Income tax expense	**$ 11,299**	$ 12,280	$ 12,882	$ (981)
Earnings before income tax	**$ 54,190**	$ 54,024	$ 54,408	$ 166
Effective income tax rate	**20.9%**	22.7%	23.7%	(1.8%)

Income tax expense decreased by $981,000 compared to 2018. The statutory tax rate was 30.0% for both 2019 and 2018.

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 2019 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 $365,056 for the current period compare to a total of $378,633 for the same period during the previous year. According to the Company, the credit total for the 2018-2019 winter season is lower than the previous season total primarily due to higher number of customer curtailment failures. There were 23 option participants in 2018-2019, compared to 22 participants in the previous year. According to the Company, changes to the Curtailment credits year over year is due to variation in demand and consumption, and the mix of option participants achieving full or partial credit.

Nothing has come to our attention to indicate that the Company is not in compliance with 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 2019 to prior years and investigated any unusual fluctuations;
- reviewed detailed listings of expenses for 2019 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 2019	Actual 2018	Actual 2017	Variance 2019-2018
Charged from Fortis Companies	**$ 2,115,024**	$ 1,904,428	$ 2,121,500	$ 210,596
Performance and restricted share units	**665,058**	346,789	687,500	318,269
Donations and charitable advertising	**336,662**	295,769	301,700	40,893
Executive short term incentive	**419,479**	514,004	361,900	(94,525)
Miscellaneous	**40,265**	61,088	45,000	(20,823)
	3,576,488	3,122,078	3,517,600	454,410
Less: Income Taxes	**1,072,946**	936,623	1,055,300	136,323
Total non-regulated (net of tax)	**$ 2,503,542**	$ 2,185,455	$ 2,462,300	**$ 318,087**

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 2019, this represents an addition to non-regulated expenses (before tax adjustment) of $419,479 (2018 - $514,004). 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 2019 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 2018 and 2019:

(000's)	2019 Actual	2018 Actual	Variance 2019 - 2018
Regulatory Assets			
Rate stabilization account	$ -	$ 1,607	$ (1,607)
OPEBs asset	21,024	24,528	(3,504)
Deferred GRA costs	706	-	706
Conservation and demand management deferral	24,815	22,549	2,266
Demand management incentive	2,687	-	2,687
Employee future benefits	86,366	82,556	3,810
Weather normalization account	8,078	2,168	5,910
Deferred income taxes	220,232	212,900	7,332
	$ 363,908	$ 346,308	$ 17,600
Regulatory Liabilities			
Rate stabilization account	$ 16,107	$ 3,979	$ 12,128
Cost recovery deferral	1,752	-	1,752
Future removal and site restoration provision	168,740	160,047	8,693
	$ 186,599	$ 164,026	$ 22,573

Rate Stabilization Account

The Rate Stabilization Account (“RSA”) primarily relates to changes in the cost and quantity of fuel used by Hydro to produce electricity sold to the Company. On July 1st of each year customer rates are recalculated in order to amortize the balance in the RSA as of March 31st over the subsequent 12-month period. In 2019, the annual July 1st rate adjustment was postponed, as ordered by the Board, to coincide with customer rate implementation as a result of Hydro’s 2017 General Rate Application, which resulted in a October 1, 2019 implementation as approved in Order No. P.U. 31 (2019).

As of December 31, 2019, there was a charge to the RSA of $10,023,800 related to the Energy Supply Cost Variance Reserve in accordance with Order No. P.U. 32 (2007) and Order No. P.U. 43 (2009), and the Wholesale Rate Change Flow-Through Account approved in Order No. P.U. 31 (2019).

Pursuant to Order No. P.U. 31 (2010) the Board approved the Company’s proposal to create the 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 31st in the year in which the difference arises. As of March 31, 2019, the credit balance of $62,200 in the OPEBVDA account was transferred to the RSA, as approved in Order No. P.U. 16 (2013).

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 accounting standards 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, 2019, the balance of $833,658 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 and approved the deferral and amortization of annual conservation program costs over seven years with recovery through the Rate Stabilization Account. As of March 31, 2019, $2,167,605 and $4,597,148 were credited to the RSA for the Weather Normalization Reserve account and for the amortization of deferred customer energy conservation program costs respectively, in accordance with Order No. P.U. 13 (2013).

The RSA is also adjusted for the Demand Management Incentive Account which has a Nil balance in 2018 therefore no impact on RSA in 2019.

Pursuant to Order No. P.U. 2 (2019) the Board approved the Company's proposed disposition of the 2019 Revenue Requirement Shortfall and differences between the actual and estimated 2019 Hearing Costs. As of March 31, 2019, the balance of $145,000 in the Revenue Requirement Shortfall account was credited to the RSA and the balance of $670,272 was debited to the RSA balance for the 2019 Hearing costs.

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 accounting standards. 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 $52.6 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. 2 (2019) the Board approved the deferral of cost related to 2019/2020 GRA as well as amortization of this deferral over a 34 month period commencing on March 1, 2019 and ending December 31, 2021. Actual costs incurred and deferred were approximately $1,000,000 with amortization of $294,000 incurred in 2019.

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, 2019 were $24,815,000 with amortization of $4,597,148 in 2019.

Demand Management Incentive

In Order No. P.U. 32 (2007) the Board approved the Company's proposal to create the Demand Management Incentive Account to replace the Purchased Power Unit Cost Variance Reserve. This account aims to isolate the demand costs and is equal to plus or minus 1% of test year wholesale demand charges. The Demand Management Incentive as at December 31, 2019 was $2,687,000 ($1,881,000 after tax).

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; and
- 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 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) 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.

In Order No. P.U. 11 (2012) the Board approved the creation of a regulatory asset of $131.2 million, rather than a reduction in the Company's equity, to reflect the accumulated difference to January 1, 2012 in defined benefit pension expense calculated under U.S. GAAP and Canadian Generally Accepted Accounting Principles.

The period over which pension expense had been recognized differed between that used for regulatory purposes and U.S. GAAP. In Order No. P.U. 13 (2013) the Board approved that pension expense for regulatory purposes be recognized in accordance with U.S. GAAP effective January 1, 2013 and that the accumulated difference in pension expense to December 31, 2012 of $12,400,000 be amortized evenly over 15 years to pension expense.

As of December 31, 2019, the regulated asset for employee future benefits was $86,366,000.

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 31st of the following year. In Order No. P.U. 10 (2020) the Board approved the December 31, 2019 net regulatory asset balance in the Weather Normalization Account of $8,078,000 ($5,654,000 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, 2019 was $220,232,000.

Cost Recovery Deferral

In 2019 there was an over-recovery of revenue due to a March 1, 2019 rate implementation date. In Order No. P.U. 2 (2019), the Board approved amortization over a 34 month period from March 1, 2019 to December 31, 2021 to provide recovery in customer rates of any 2019 revenue shortfall/over-recovery associated with the March 1, 2019 rate implementation. The over-recovery of revenue was approximately $2,482,000 with accumulated amortization of $730,000. The net regulating liability for deferred costs – 2019 Cost Recovery Deferral at December 31, 2019 was approximately $1,752,000.

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 2019 the balance in this account was $168,740,000 (2018 - $160,047,000).

Based upon our analysis, nothing has come to our attention to indicate that changes in regulatory deferrals for 2019 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 accounting standards 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 2019 PEVDA was calculated at $833,658. This balance was transferred to the Rate Stabilization Account as a charge on March 31, 2019 in accordance with Order No. P.U. 43 (2009).

We confirm that the 2019 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 accounting standards 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 2019 OPEBVDA was calculated at $62,200. This balance was transferred to the Rate Stabilization Account as a charge on March 31, 2019 in accordance with Order No. P.U. 31 (2010).

We confirm that the 2019 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 2019 are as follows:

1. Made capital investments of $109 million of which over 46% 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;

4. Continued the Substation Modernization and Refurbishment program;

5. Continued to install down line reclosers to provide for improved control over the distribution system along with the ability to locate and isolate system trouble;

6. The Company implemented an ergonomics and soft tissue injury prevention program. Job demands analyses were completed for all operations positions, and training on the various components of the program started Company-wide;

7. The Company replaced its incident tracking and reporting system with a new Intelex incident management module. Intelex will allow improved reporting abilities, real time data analysis, and integration with other Intelex safety management modules already in service;

8. A safety consultant from The Engine Room provided safety leadership training to supervisors across the Company. Training included work observation coaching and one-on-one mentoring with supervisors;

9. Continued to build a relationship with the Forestry Safety Association of Newfoundland and Labrador ("FSANL") to increase awareness and prevent public contacts related to wood harvesting. A safety brochure has been developed by Newfoundland Power, and FSANL has agreed to supply a copy to people when acquiring cutting permits;

10. TakeCharge partnered with Dunsky Energy Consulting to conduct a conservation potential study to provide a high-level understanding of the energy conservation, demand response, fuel-switching and vehicle electrification opportunities that exist in the province. The results of the study are being used to develop the Company's next five-year conservation plan to be filed with the Board in 2020;

11. Work began on developing Newfoundland Power's Climate Change Adaptation Plan. The Company also initiated a gap analysis to verify its alignment with the national criteria established through the Canadian Electricity Association's Sustainable Electricity Brand;

12. An employee safety climate survey was conducted. This questionnaire, which is designed to assess the Company's safety culture, was consistent with the previous assessment in 2017, and the employee response rate was slightly higher. The survey responses in 2019 remain positive, with an overall average score of over 88%. The results will be further analyzed and an action plan will be developed in the first quarter of 2020;

13. Customer participation in the Company's self-service programs continued to increase. At the end of the year, 49% of customer accounts had subscribed to ebills, an increase of 2.4% from 2018;

14. The Company engaged CanSustain to compare Newfoundland Power's operations with the International Standard ISO 26000:2010 – Guidance on Social Responsibility. The standard addresses a broad range of environmental, social and governance indicators, and is the basis of the CEA utility sustainability program. Overall, the assessment indicated strong alignment. Full analysis of the results, and development of an action plan will be completed in the first quarter of 2020;

15. On track to comply with federal regulations regarding the removal of polychlorinated biphenyls (“PCBs”) from specific substation equipment by 2025. In 2019 the Company replaced three power transformers and eight breakers;

16. Combined the office and service buildings in Burin. The new building improves operating efficiency and is more energy efficient;

17. The Company established its cybersecurity governance structure and clarified management roles and oversight processes. Preparation is ongoing for the 2020 implementation of a new system to coordinate access management for critical technology, and improvements to documentation of cybersecurity controls are continuing;

18. Meter reading performance continued to improve. 2019 was the second year of full Automated Meter Reading (“AMR”). Through ongoing technology improvements, there has been a further 28% reduction in customer bill estimates due to unavailable meter readings, compared to 2018;

19. The high-volume call answering system that drives Newfoundland Power’s outage information phone line was replaced with a virtual cloud-based solution in the fourth quarter. The new system can handle more callers simultaneously and provides customers with address-specific outage information automatically based on the caller’s phone number. It also provides improved message administration, combining pre-recorded messaging with text-to-speech capabilities;

20. A new Outage Management System (“OMS”) was implemented in 2019. The new OMS integrates key operations and customer service applications. It allows the Company to more effectively manage outages and provide customers with detailed up-to-date information through the contact center, website and direct notifications; and

21. A new incident management system was launched. The new Intelex module will functionally replace the previous system and offer new and improved ways to manage and report on safety and environmental metrics.

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 2017	Actual 2018	Actual 2019	Plan 2019	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1]	2.28	2.65	2.34	2.39	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply[1]	1.66	1.67	1.62	1.85	Yes
	Plant Availability (%)[2]	91.3	96.3	95.7	95.0	Yes
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	86.5	85.6	85.8	85.6	Yes
	Call Centre Service Level (% per second)[3]	80/60	81/60	77/60	80/60	No
	Trouble Call Responded to Within 2 Hours (%)	87.0	85.0	81.0	85.0	No
Safety	All Injury/Illness Frequency Rate	0.7	0.9	0.4	0.9	Yes
Financial	Earnings (millions)[4]	$41.0	$41.2	$42.3	$40.9	Yes
	Gross Operating Cost/Customer[5]	$264	$225	$229	$232	Yes

[1] 2017 statistics exclude the impact of snow storms in March & December. 2018 statistics exclude the impact of wind storms in April & November and a Power Transformer failure in November. 2019 statistics exclude the impact of a wind storm in February, Hurricane Dorian in September and a snow storm in November.
[2] Excludes the hours of generation unit is out of service due to system disruptions and major plant refurbishment.
[3] Service level is based on calls answered in 60 seconds.
[4] Earnings applicable to common shares.
[5] Excluding conservation program costs, pension, OPEBs and early retirement program costs.

The following table compares whether the Company measures were achieved during the 2017, 2018, and 2019 years:

Category	Measure	Measure Achieved 2017	Measure Achieved 2018	Measure Achieved 2019
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply	Yes	No	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply	Yes	Yes	Yes
	Plant Availability (%)	No	Yes	Yes
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	No	No	Yes
	Call Centre Service Level (% per second)	Yes	Yes	No
	Trouble Call Responded to Within 2 Hours (%)	Yes	Yes	No
Safety	All Injury/Illness Frequency Rate	Yes	No	Yes
Financial	Earnings (millions)	Yes	Yes	Yes
	Gross Operating Cost/Customer	Yes	No	Yes