Board of Commissioners of Public Utilities

Financial Consultants Report
2021 Annual Financial Review of
Newfoundland Power Inc.

Table of Contents

Restrictions, Qualifications and Independence

Purpose

This report was prepared for the Board of Commissioners of Public Utilities ("the Board") in Newfoundland and Labrador. The purpose of our engagement was to present our observations, findings and recommendations with respect to our 2021 annual financial review of Newfoundland Power Inc. ("the Company") ("Newfoundland Power").

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 and will also be available on the Board's website. We have given the Board our consent to use our report for these purposes.

This report shall be solely for the benefit of the Board and not for the benefit of any third party and may be relied upon only for the purpose for which the report is intended as contemplated and/or defined within the engagement. Grant Thornton recognizes no responsibility whatsoever, other than that owed to the Board as at the date on which the report is given to the Board by Grant Thornton, for any unauthorized use of or reliance on the report.

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 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 presents our observations and findings with respect to our 2021 Annual Financial Review of Newfoundland Power. Below is a summary of the key observations and findings included in our report.

- The average rate base for 2021 was $1,202,946,000 which is an increase of $21,049,000 (1.75%) over the average rate base for 2020 of $1,181,897,000. The Company's calculation of the return on average rate base for 2021 was 6.74% (2020 – 7.04%) compared to an approved rate of return of 6.65%. The actual rate of return was within the range approved by the Board (6.47% to 6.83%). 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 2021 was $521,048,000 (2020 - $516,759,000). The Company's actual return on average common equity for the year ended December 31, 2021 was 8.88% (2020 – 8.93%). In Order No. P.U. 32 (2007), the Board ordered that if 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 2021 the approved cost of common equity was 8.50% as per Order No. P.U. 36 (2020). The actual return on average common equity for 2021 was 8.88% as noted above. This return was within the 50-basis point limit and as such no report was required.

- Total actual capital expenditures (excluding capital projects carried forward from prior years) were 12.58% under budget in 2021. Total capital expenditures (including projects carried over from prior years) were over the approved budget on a net basis by $1,721,000 (1.09%). However, for each category of expenditure, the variances ranged from an over-budget of 8.02% to an under-budget of 100.00%.

- The Company experienced a 0.32% decrease in revenue from rates in 2021 as compared to 2020. The decrease is primarily due to lower electricity sales from residential customers.

- Overall, net operating expenses increased by $1,307,000 from 2020 to 2021. Significant operating expense variances are discussed throughout our report. We conducted an examination of other costs including, depreciation, interest and income taxes and have noted that nothing has come to our attention to indicate that these costs for 2021 are unreasonable.

- During our review of non-regulated expenses, nothing came 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.

- The 2021 Pension Expense Variance Deferral Account ("PEVDA") operated in accordance with Order No. P.U. 43 (2009).

- The 2021 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 2021 the Company met eight out of nine of its planned performance measures. The Company fell short of its targets in "Outage Hours/Customer (SAIDI)", as discussed later in this report.

Introduction

This report to the Board presents our observations and findings with respect to our 2021 Annual Financial Review of Newfoundland Power.

Scope and Limitations

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

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

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

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

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

   - advertising;
   - amortization of regulatory costs;
   - bad debts (uncollectible bills);
   - company pension plan;
   - conservation and demand management;
   - costs associated with curtailable rates;
   - 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), Order No. P.U. 32 (2007), Order No. P.U. 43 (2009), and Order No. P.U. 13 (2013).

5. Examine the Company's 2021 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 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 based on the nature 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 financial statements of the Company for the year ended December 31, 2021 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 10, 2022. 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

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

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 31, 2022, the Company filed its 2021 Annual Report to the Board. The Company noted in the report that there are no significant changes to the system of accounts, only minor wording changes were made to improve the clarity and accuracy of the 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 approved 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, 2021 which is included on Return 3 of the annual report to the Board was calculated using the Asset Rate Base Method ("ARBM"). The average rate base for 2021 was $1,202,946,000 which is an increase of $21,049,000 (1.75%) over the average rate base for 2020 of $1,181,897,000. 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 2021; 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 2020 and 2021 (all figures shown are averages):

(000)'s	2021	2020
Net Plant Investment (average)		
Plant Investment	$ 2,062,375	$ 1,987,608
Accumulated Depreciation	(848,714)	(809,124)
CIAC's	(44,569)	(44,487)
	1,169,092	1,133,997
Additions to Rate Base (average)		
Deferred Charges (a)	89,465	90,916
Cost Recovery Deferral for Hearing Costs (b)	124	371
Cost Recovery Deferral – Conservation (c)	16,735	17,210
Customer Finance Programs (d)	1,927	2,296
Demand Management Incentive Account (e)	1,172	1,442
Weather Normalization Reserve (f)	-	960
	109,423	113,195
Deductions from Rate Base (average)		
Weather Normalization Reserve (f)	2,877	-
Other Post-Employment Benefits (g)	70,153	64,265
Customer Security Deposits (h)	1,307	1,316
Accrued Pension Obligation (i)	5,213	5,181
Deferred Income Taxes (j)	14,330	11,386
Cost Recovery Deferral – 2016 Cost Recovery Deferral (k)	307	920
	94,187	83,067
Average Rate Base before Allowances	1,184,330	1,164,125
Rate Base Allowances		
Materials and Supplies	8,339	7,270
Cash Working Capital	10,277	10,503
	18,616	17,773
Average Rate Base	$ 1,202,946	$ 1,181,897

(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 $89,465,000 (2020 - $90,916,000) included in the 2021 rate base consists of average deferred pension costs of $89,394,000 (2020 - $90,862,000) and credit facility costs of $71,000 (2020- $54,000). 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 2021 average rate base includes an addition of $124,000 (average of $247,000 and $Nil for 2020 and 2021 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.

In Order No. P.U. 3 (2022), the Board approved the amortization of annual costs over 10 years, commencing January 1, 2021 for historical balances and annual charges. The implementation of Order No. P.U. 3 (2022) resulted in a $1,875,000 true-up increase in deferred conservation costs in 2022 relating to annual deferred customer energy conservation program costs incurred up to December 31, 2021.

In 2021, the actual costs incurred and deferred were $4,991,000 ($3,494,000 after tax) and the amortization will be $499,000 beginning in 2022; the 2021 deferred conservation balance would not include the implementation of the change in amortization to 10 years as the amortization is booked the year after incurred. Included in the calculation of the average rate base for 2021 is $16,735,000 (2020 - $17,210,000) 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 2021 average rate base incorporates $1,926,000 (2020 - $2,296,000) related to these programs.

(e) In Order No. P.U. 14 (2021), the Board approved the disposition of the 2020 balance of the Demand Incentive Account of $1,431,000 ($1,002,000 after tax) by means of a debit to the Rate Stabilization Account as of March 31, 2021. In Order No. P.U. 10 (2022), the Board approved the disposition of the 2021 balance of the Demand Incentive Account of $1,917,000 ($1,342,000 after tax) by means of a debit to the Rate Stabilization Account as of March 31, 2022. The 2021 average rate base incorporates $1,172,000 (2020 - $1,442,000) related to this account.

(f) During 2021, 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 decrease to the reserve of $3,734,000 in 2021 (2020 – $5,654,000 increase).

Other transfers:

i. $10,366,000 increase to the reserve related to the after-tax impact of the Degree Day Normalization Reserve Transfer (2020 – $3,856,000 increase).
ii. $8,346,000 decrease to the reserve related to the after tax impact of the Hydro Production Equalization Reserve transfer (2020 - $122,000 decrease).

The net impact was a net increase to the reserve of $1,714,000 (2020 - $9,388,000 decrease). The ending balance in this reserve account totaled $2,020,000 compared to a balance of 3,734,000 at December 31, 2020 (an average of ($2,877,000) for 2021) (2020 – ($960,000)). This represents a balance owed to customers.

(g) Other Post-Employment Benefits is equal to the difference, at December 31, 2021, between the OPEBs liability of $88,675,000 and the OPEBs asset of $15,109,000. The calculation of the 2021 average rate base of $70,152,000 is equal to the average of the December 31, 2021 net liability of $73,566,000 and the December 31, 2020 net liability of $66,739,000.

(h) Customer Security Deposits are comprised of security deposits received from customers for electrical services as outlined with the Board approved Schedule of Rates, Rules and Regulations. The calculation of the 2021 average rate base incorporates $1,306,000 (2020 - $1,316,000) related to customer security deposits.

(i) The 2021 average rate base calculation incorporates $5,213,000 (2020 - $5,182,000) 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 2021 average rate base is ($3,401,000) and ($18,129,000) respectively. The remaining balance of the deferred income tax liability in the amount of $35,860,000 relates to capital assets. This results in an average balance for deferred income tax liability of $14,330,000 (2020 - $11,386,000).

(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) revenue surplus from March 1, 2019 rate implementation of rates. The 2021 average rate base includes a deduction of $307,000 (2020 - $920,000).

The net change in the Company's average rate base from 2020 to 2021 can be summarized as follows:

(000's)	2021	2020
Average rate base - opening balance	**$ 1,181,897**	$ 1,153,556
Change in average deferred charges and deferred regulatory costs	**(1,560)**	471
Average change in:		
Plant in service	**74,767**	78,115
Accumulated depreciation	**(39,590)**	(37,536)
Contributions in aid of construction	**(82)**	(2,891)
Weather normalization reserve	**(3,837)**	(2,626)
Other post-employment benefits	**(5,887)**	(4,814)
Future income taxes	**(2,944)**	(3,898)
Rate base allowances	**843**	1,391
Customer Finance Programs	**(369)**	(181)
Demand Management Incentive Acct	**(269)**	501
Other rate base components (net)	**(23)**	(191)
Average rate base - ending balance	**$ 1,202,946**	$ 1,181,897

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2021 average rate base, and therefore conclude that the 2021 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 2021 was 6.74% (2020 – 7.04%). 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. The return on average rate base is calculated in accordance with the methodology approved in Order No. P.U. 32 (2007).

The actual return on average rate base in comparison to the range of allowed return for each of the years from 2019 to 2021 is set out in the table below.

	2021	2020	2019
Actual Return on Average Rate Base	**6.74%**	7.04%	6.97%
Upper End of Range set by the Board	**6.83%**	7.22%	7.19%
Lower End of Range set by the Board	**6.47%**	6.86%	6.83%

The Board approved the Company's rate of return on average rate base of 6.65% in a range of 6.47% to 6.83% for 2021 in Order No. P.U. 36 (2020). As noted above, the Company's actual return on average rate base for 2021 was 6.74% which was inside 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. 13 (2013) regarding the capital structure for Newfoundland Power 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 2021 as reported in Return 24 is as follows:

	2021 Average		2020	2019
	(000's)	Percent	Percent	Percent
Debt	$ 638,598	55.07%	54.70%	54.28%
Preferred equity (1)	-	0.00%	0.39%	0.78%
Common equity	521,048	44.93%	44.91%	44.94%
	$ 1,159,646	100%	100%	100%

Note 1 – The Company's preferred shares were redeemed in 2020.

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 2021 in Return 26. The embedded cost of debt for 2021 was 5.61% which represents a 37 bps decrease from the 2020 embedded cost of debt of 5.98%.

Based on the information indicated above, we conclude that the capital structure included in the Company's annual report to the Board is in accordance 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, 2021 is included on Return 27 of the annual report to the Board. The average common equity for 2021 was $521,048,000 (2020 - $516,759,000). The Company's actual return on average common equity for 2021 was 8.88% (2020 – 8.93%).

Our procedures 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 common equity per Order No. P.U. 40 (2005), including the deemed capital structure per Order Nos. P.U. 19 (2003), P.U. 32 (2007), P.U. 43(2009), P.U. 13 (2013), P.U. 18 (2016), and P.U. 2 (2019); and,
- recalculated the rate of return on common equity for 2021 and ensured it was in accordance with Order Nos. P.U. 32 (2007) and P.U. 36 (2020).

In Order No. P.U. 32 (2007), the Board ordered that where in a given year the actual rate of 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. Per Order No. P.U. 2 (2019) the approved cost of common equity for 2021 was 8.50%. The actual return on average common equity for 2021 was 8.88%. Therefore, the actual return on average common equity was within the 50-basis point limit and no additional reporting 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)	**2021**	**2020**	**2019**
Net Income	**$ 43,757**	$ 43,577	$ 42,892
Income Taxes	**11,603**	11,893	11,298
Interest on long term debt	**35,450**	36,811	35,375
Interest during construction	**(995)**	(949)	(1,933)
Other interest and amortization of discount costs	**400**	842	1,590
Total	**$ 90,215**	$ 92,174	$ 89,222
Interest on long term debt	**$ 35,450**	$ 36,811	$ 35,375
Other interest and amortization of discount costs	**400**	842	1,590
Total	**$ 35,850**	$ 37,653	$ 36,965
Interest Coverage (times)	**2.5**	2.4	2.4

The above table shows that the interest was consistent from 2018 to 2020 with a slight increase in 2021.

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 2021 is 2.5 times.

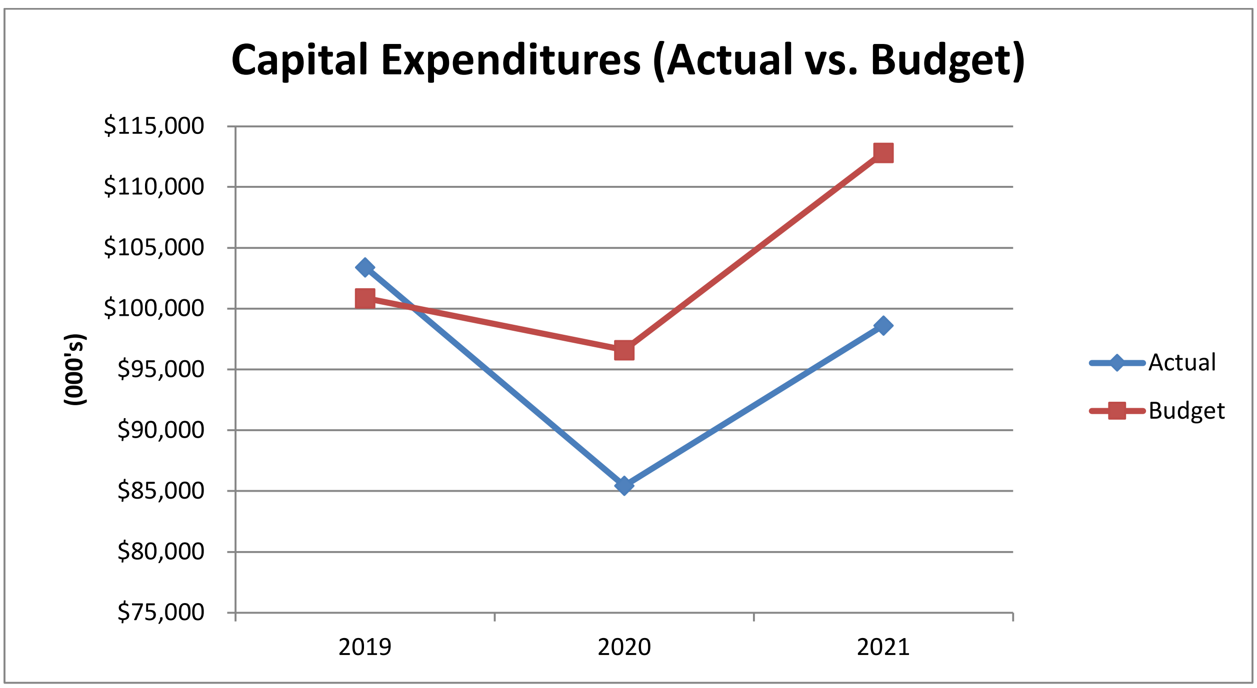
Capital Expenditures

Scope: ***Review the Company's 2021 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 2019 to 2021:

($000's)	2019	2020	2021	Notes
Actual	$ 103,417	$ 85,447	**$ 98,640**	**1**
Budget	$ 100,856	$ 96,614	**$ 112,836**	
Over (under) budget	2.54%	(11.56%)	**(12.58%)**	

Note 1: Total expenditures per the 2021 Capital Budget report includes the carryover amount of $17,285,000 for a total of $115,925,000. The carryover amount is made up of eight projects included in the following categories; $300,000 to Generation; $2,547,000 to Substation; $1,237,000 to Transmission; $2,950,000 to Distribution, $351,000 to General property, $2,415,000 to Transportation, $112,000 to Telecommunication, and $7,373,000 to Information Systems. According to the Company, these expenditures will occur in 2022.



The following table provides a summary of the capital expenditure activity in 2021 as reported in the Company's *"2021 Capital Expenditure Report"*:

($000's)	Capital Budget			Actual Expenditures		
	Prior Years	2021	Total	Prior Years	2021	Total
2021 Capital Projects (1)	$ -	$ 112,836	$ 112,836	$ -	$ 98,640	$ 98,640
2020 Projects Carried to 2021 & Multi Year Projects						
Transmission line rebuild	9,623	-	9,623	8,002	2,067	10,069
Application enhancement	1,428	-	1,428	1,346	206	1,552
Systen Upgrades	2,592	-	2,592	2,422	402	2,824
Company Building Renovations	1,172	-	1,172	1,116	76	1,192
Purchase Vehicles and Aerial Devices	3,869	-	3,869	2,254	1,261	3,515
Purchase Mobile Generation	13,915	-	13,915	13,257	102	13,359
Topsail Hydro Plant Refurbishment	485	-	485	319	170	489
Petty Harbour Hydro Plant Refurbished	3,662	-	3,662	337	3,162	3,499
Rattling Brook Plant Refurbishment	1,183	-	1,183	100	785	885
Hydro Facility Rehabiliation	1,519	-	1,519	1,368	50	1,418
Substation Feeder Termination	290	-	290	76	203	279
Trunk Feeders	2,820	-	2,820	707	1,560	2,267
Feeder Additions for Load Growth	2,302	-	2,302	1,718	426	2,144
	44,860	-	44,860	33,022	10,470	43,492
Grand Total	**$ 44,860**	**$ 112,836**	**$ 157,696**	**$ 33,022**	**$109,110**	**$ 142,132**

Note 1 - Approved in Order Nos. P.U. 37 (2020), P.U. 12 (2021) and P.U. 30 (2021).

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

($000's)	2021 Budget (1)	2021 Actuals (2)	Variance	Carryover (3)	Variance Including Carryover	%
Generation - Hydro	**18,029**	**15,548**	(2,481)	300	(2,181)	(12.10%)
Generation - Thermal	**14,245**	**13,659**	(586)	-	(586)	(4.11%)
Substation	**14,570**	**13,191**	(1,379)	2,547	1,168	8.02%
Transmission	**19,374**	**19,227**	(147)	1,237	1,090	5.63%
Distribution	**52,535**	**52,227**	(308)	2,950	2,642	5.03%
General property	**3,948**	**3,512**	(436)	351	(85)	(2.15%)
Transportation	**7,901**	**5,198**	(2,703)	2,415	(288)	(3.65%)
Telecommunications	**462**	**312**	(150)	112	(38)	(8.23%)
Information systems	**19,382**	**12,463**	(6,919)	7,373	454	2.34%
Unforeseen	**750**	**-**	(750)	-	(750)	(100.00%)
General expenses capitalized	**6,500**	**6,795**	295	-	295	4.54%
Total	**$ 157,696**	**$ 142,132**	**($15,564)**	**$ 17,285**	**$ 1,721**	**1.09%**

Note 1 - Includes prior years projects and current year budgeted amounts as there were projects incomplete at the previous year ends.
Note 2 - 2021 actuals include the total expense for projects carried forward from 2020.
Note 3 - Represents $17,285,000 in capital projects carried forward to 2022.

As indicated in the table, actual capital expenditures were less than the approved budget by $15,564,000 and when carryover amounts are considered, they were $1,721,000 (1.09%) higher. However, for each category of expenditure, the variances ranged from an over-budget of 8.02% for the substation 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)
Additions Due to Load Growth	2,547
Transmission Line Extension - 35L	1,237
Trunk Feeders	792
Feeder Additions for Load Growth	671
Utility EV Charging Network	1,487
Company Building Renovations	351
Purchase Vehicles and Aerial Devices	2,415
Fibre Optic Cable Builds	112
Application Enhancements	186
Network Infrastructure	94
Topsail Hydro Plant Refurbishment	300
Customer Service System Replacement	7,093
Total Carryover	**$ 17,285**

The Company has provided detailed explanations on budget to actual variances in Appendix A of its "2021 Capital Expenditure Report".

Adherence to Capital Budget Application Guidelines

Based on our review, the Company's 2021 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% off the approved budget.

- 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 2.54% in 2019, (11.56%) in 2020 and (12.58%) in 2021. When taking into consideration carryovers, the variance was 5.21% in 2019, 0.63% in 2020 and 1.09% in 2021 resulting in no additional reporting requirements.

The allowance for unforeseen items account was not utilized in 2021.

Capital Expenditure Reports

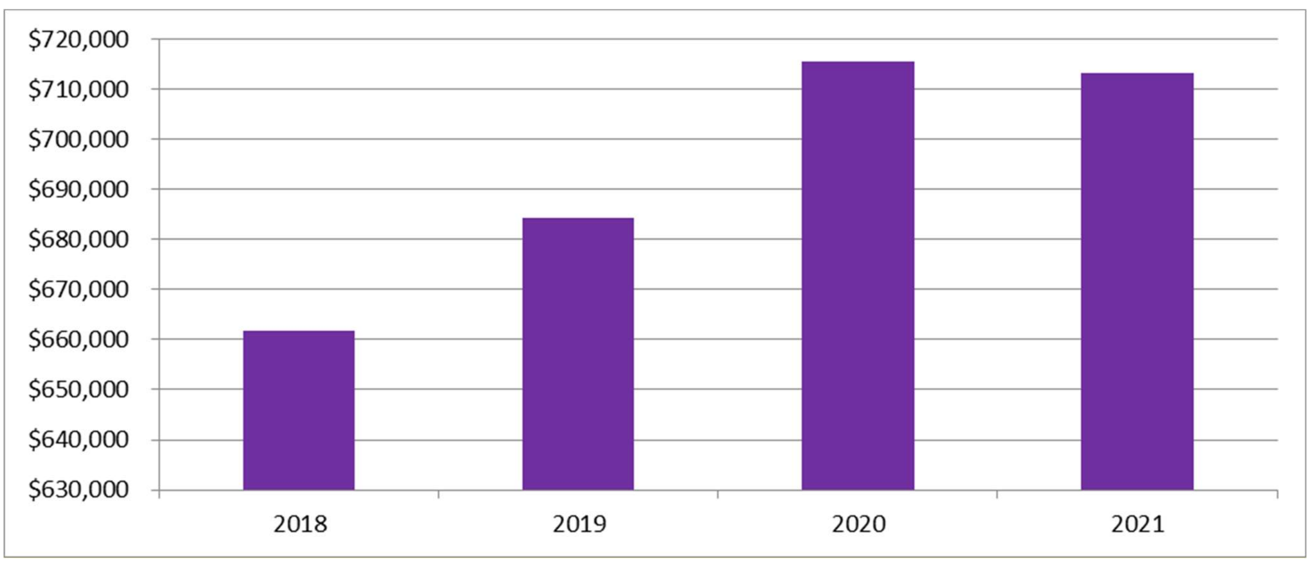
The Company filed quarterly Capital Expenditure reports for the 2021 calendar year on time.

Revenue from rates

Scope: ***Review the Company's 2021 revenue from rates in comparison to prior years and follow up on any significant variances.***

We have compared the actual revenues from rates for 2018 to 2021 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

($000's)	2018	2019	2020	2021
Residential	$ 419,389	$ 432,272	$ 458,433	**$ 453,328**
General Service				
0-100 kW	90,364	93,038	93,282	**96,298**
110-1000 kVA	97,338	101,397	105,418	**107,731**
Over 1000 kVA	35,725	37,916	38,643	**36,428**
Streetlighting	16,255	16,664	16,983	**16,958**
Discounts forfeited	2,643	2,892	2,868	**2,560**
Revenue from rates	$ 661,714	$ 684,179	$ 715,627	**$ 713,303**
Year over year percentage change	-0.03%	3.39%	4.60%	**-0.32%**



The above graph demonstrates that the Company has seen a 0.32% decrease in revenue from rates in 2021 as compared to 2020. The decrease is primarily due to lower electricity sales from residential customers.

The comparison by rate class of 2021 actual revenues to 2021 budget is as follows:

($000's)	2020	2021	2021 Plan	Actual - Plan Variance	%
Residential	$ 458,433	**$ 453,328**	**$ 450,866**	$ 2,462	0.55%
General Service					
0-100 kW	93,282	**96,298**	**99,776**	(3,478)	(3.49%)
110-1000 kVA	105,418	**107,731**	**109,753**	(2,022)	(1.84%)
Over 1000 kVA	38,643	**36,428**	**41,636**	(5,208)	(12.51%)
Streetlighting	16,983	**16,958**	**16,887**	71	0.42%
Discounts forfeited	2,868	**2,560**	**2,880**	(320)	(11.11%)
Total revenue from rates	$ 715,627	**$ 713,303**	**$ 721,798**	$ (8,495)	(1.18%)

We have also compared the 2021 budget energy sales in GWh to the actual sold in 2021:

(GWH'S)	2020	2021	2021 Plan	Actual - Plan Variance	%
Residential	3,547.0	**3,499.2**	**3,481.9**	17.3	0.50%
General Service					
0-100 kW	749.4	**778.5**	**800.0**	(21.5)	(2.69%)
110-1000 kVA	990.2	**1,018.4**	**1,031.8**	(13.4)	(1.30%)
Over 1000 kVA	410.1	**388.3**	**443.9**	(55.6)	(12.53%)
Streetlighting	32.3	**30.6**	**30.9**	(0.3)	(0.97%)
Total	5,729.0	**5,715.0**	**5,788.5**	(73.5)	(1.27%)

Actual 2021 revenue from rates was lower than 2021 Plan with an overall decrease in actual sales of $8,495,000 (1.18%) from the 2021 Plan due to decreased electricity sales. There was a 1.27% decrease in GWh sold in 2021 compared to 2021 Plan which was primarily due to the lower average use by commercial customers due to the Covid-19 pandemic. The largest variance in revenue can be seen in the Over 1000 kVA, the 0-100 kW, and the Residential class where revenues decreased by $5,208,000 (12.51%), decreased by $3,478,000 (3.49%), and increased by $2,462,000 (0.55%), 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.

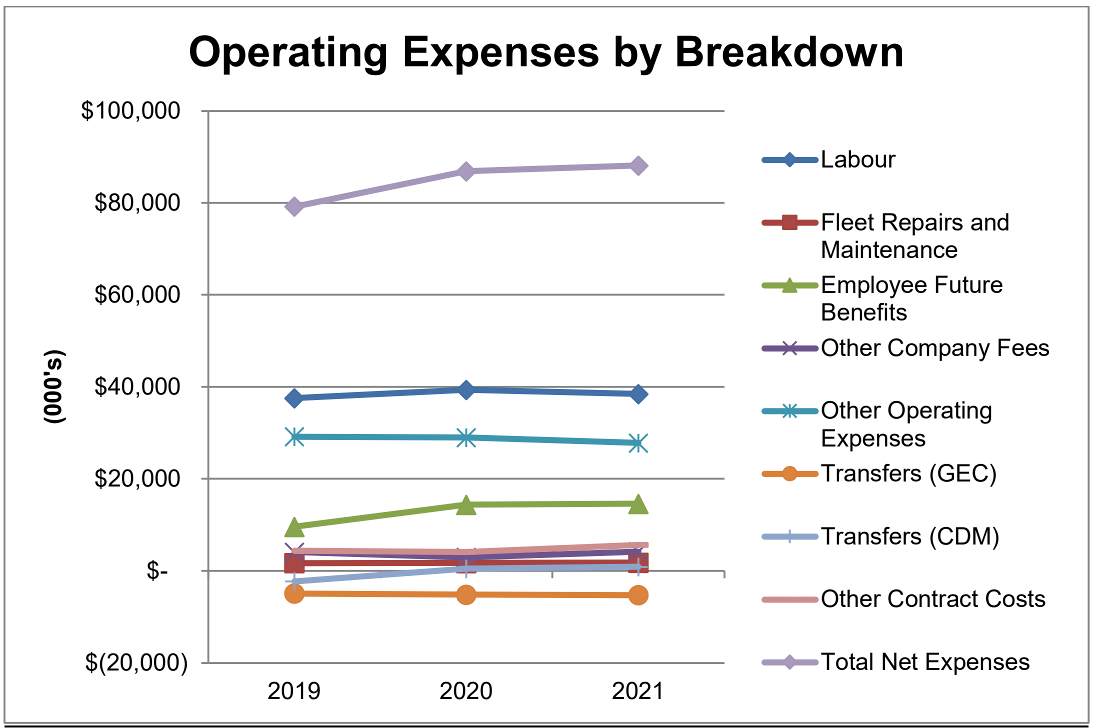
The below table provides details of operating and general expenses (including non-regulated expenses) by "breakdown" for 2019, 2020, and 2021.

(000's)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Labour	$ 40,055	$ 40,652	$ 38,603	$ (597)
Reclass OPEB labour cost	(1,615)	(1,290)	(1,041)	(325)
Total Labour	38,440	39,362	37,562	(922)
Vehicle expense	1,813	1,725	1,681	88
Operating materials	1,075	1,301	1,361	(226)
Inter-company charges	1,995	2,277	2,058	(282)
Plants, Subs, System Oper & Bldgs	3,495	3,484	3,267	11
Travel	678	638	1,142	40
Tools and clothing allowance	1,143	1,156	1,289	(13)
Miscellaneous	1,882	1,999	2,005	(117)
Conservation	1,652	2,172	2,813	(520)
Taxes and assessments	1,337	1,116	1,156	221
Uncollectible bills	1,111	2,290	1,980	(1,179)
Insurance	1,995	1,698	1,397	297
Severance & other employee costs	(17)	126	132	(143)
Education, training, employee fees	338	275	444	63
Trustee and directors' fees	686	673	518	13
Other company fees	4,186	2,944	4,058	1,242
Stationary & copying	168	246	257	(78)
Equipment rental/maintenance	664	656	790	8
Communications	2,874	2,786	2,803	88
Advertising	1,412	1,264	1,581	148
Vegetation management	2,524	2,306	2,042	218
Computing equipment & software	2,461	2,199	1,830	262
Total Other	33,472	33,331	34,604	141
Pension & early retirement program	6,966	7,864	3,335	(898)
OPEB's	7,630	6,528	6,241	1,102
Total employee future benefits	14,596	14,392	9,576	204
Total gross expenses	86,508	87,085	81,742	(577)
Transfers (GEC)	(5,276)	(5,175)	(4,913)	(101)
CDM amortization	5,889	5,578	4,597	311
Other contract expenses	5,667	4,120	4,353	1,547
Deferred CDM program costs	(4,991)	(5,118)	(6,864)	127
Deferred regulatory costs	353	353	294	-
Total net expenses	**$ 88,150**	**$ 86,843**	**$ 79,209**	**$ 1,307**

Overall, net operating expenses increased by $1,307,000 from 2020 to 2021. 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 2021 are unreasonable.

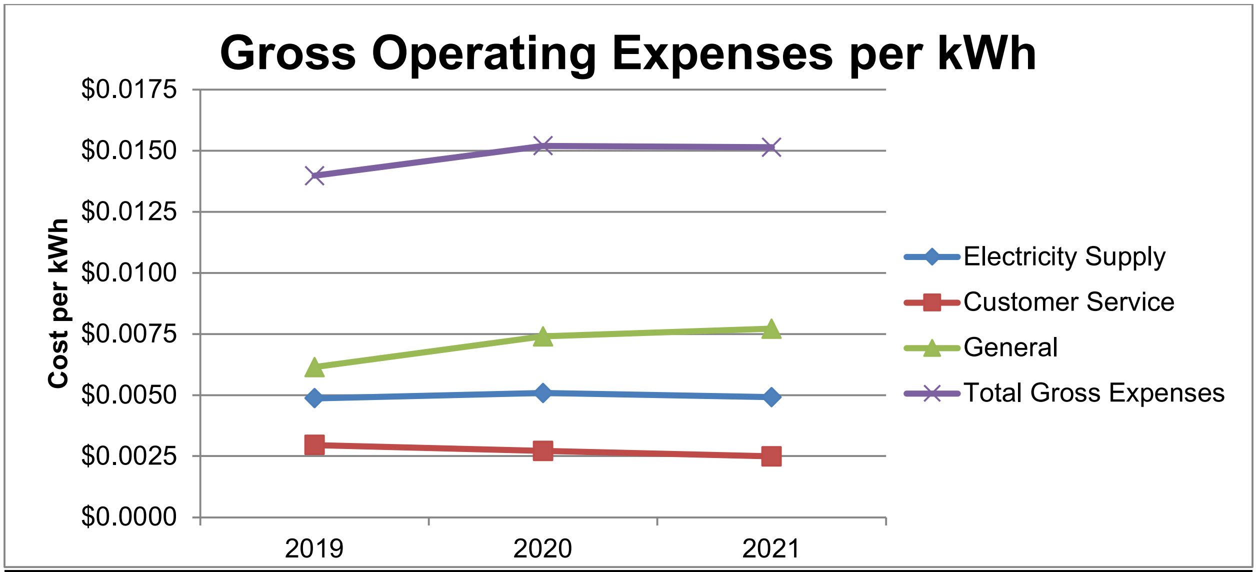
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph show the trend in net operating expenses by breakdown for the period 2019 to 2021.

	Actual		
(000's)	**2019**	**2020**	**2021**
Labour	$ 37,562	$ 39,362	**$ 38,440**
Fleet Repairs and Maintenance	1,681	1,725	**1,813**
Employee Future Benefits	9,576	14,392	**14,596**
Other Company Fees	4,058	2,944	**4,186**
Other Operating Expenses	29,159	29,016	**27,826**
Transfers (GEC)	(4,913)	(5,175)	**(5,276)**
Transfers (CDM)	(2,267)	460	**898**
Other Contract Expenses	4,353	4,119	**5,667**
Total Net Expenses	$ 79,209	$ 86,843	**$ 88,150**



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2019 to 2021 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
2019	5,846,600	$28,473	$0.0049	$17,298	$0.0030	$35,970	$0.0062	$81,742	$0.0140
2020	5,729,000	$29,144	$0.0051	$15,555	$0.0027	$42,386	$0.0074	$87,085	$0.0152
2021	5,715,000	$28,095	$0.0049	$14,282	$0.0025	$44,131	$0.0077	$86,508	$0.0151



The table and graph show that total gross expenses per kWh have decreased by approximately 0.7% compared to 2020.

There was an increase in General Costs of $1.7 million, with a decrease in Customer Service Costs of $1.3 million and a decrease in Electricity Supply Costs of $1.0 million. The results of our review of the individual significant expense categories variances are noted on the following pages.

Salaries and Benefits (including executive salaries)

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 2019 to 2021 (including 2021 Plan) is as follows:

	Actual 2021	**Plan 2021**	**Actual 2020**	**Actual 2019**	**Actual - Plan**	**Actual 2021-2020**
Executive Group	**6.0**	**6.0**	6.0	6.2	-	-
Corporate Office	**22.2**	**21.2**	21.6	20.8	1.0	0.6
Finance	**97.4**	**100.1**	96.6	93.5	(2.7)	0.8
Engineering and Operations	**368.4**	**386.2**	382.7	383.2	(17.8)	(14.3)
Customer Relations	**95.0**	**92.3**	70.6	72.8	2.7	24.4
	589.0	**605.8**	577.5	576.5	(16.8)	11.5
Temporary employees	**18.5**	**21.2**	34	39.7	(2.7)	(15.5)
Total	**607.5**	**627**	611.5	616.2	(19.5)	(4.0)

The overall number of FTE's in 2021 compared to 2020 decreased by 4.0. The budgeted number of FTEs in the 2021 Plan was 627.0 versus actual of 607.5. The variances between 2021, 2021 Plan, and 2020 are the result of the following:

- Finance & Information Technology for 2021 is lower than plan primarily due to delayed hires to replace transfers to the CIS Project. 2021 is consistent with 2020.
- Engineering & Operations for 2021 is lower than plan and 2020 primarily due to delayed hires as a result of COVID-19.
- Customer Relations for 2021 is higher than plan primarily due to transfers in from the CIS Project, partially offset by delayed hires for Electrification Program. 2021 is higher than 2020 primarily due to a shift from temporary to regular employees and transfers in from the CIS Project.
- Temporary Employees for 2021 is lower than plan and 2020 primarily due to a shift from temporary to regular employees.

An analysis of salaries and wages by type of labour and by function from 2019 to 2021 is as follows:

(000's)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Type				
Internal labour *(1)*	**$ 69,839**	$ 69,028	$ 66,023	$ 811
Overtime *(2)*	**6,635**	5,886	6,568	749
	76,474	74,914	72,591	1,560
Contractors *(3)*	**15,441**	12,510	17,523	2,931
	$ 91,915	$ 87,424	$ 90,114	$ 4,491
Function				
Operating *(4)*	**$ 40,055**	$ 40,652	$ 38,603	$ (597)
Capital and miscellaneous *(5)*	**51,860**	46,772	51,511	5,088
Total	**$ 91,915**	$ 87,424	$ 90,114	$ 4,491
Year over year percentage change	**5.14%**	-2.99%	3.50%	

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 2021 were $4,491,000 (5.14%) higher than 2020.

Note 1 - Internal labour for 2021 was higher than 2020 due primarily to inflationary increases.

Note 2 - Overtime labour for 2021 was higher than 2020 primarily due to higher overtime associated with (i) capital distribution work and (ii) capital generation work. This increase was partially offset by the overtime associated with restoration efforts required following storms in 2020.

Note 3 - Contract labour for 2021 was higher than 2020 due to higher labour for (i) transmission line rebuilds and deficiencies, and (ii) capital distribution work.

Note 4 - Operating labour for 2021 was lower than 2020 due primarily to shift to capital distribution work, partially offset by labour inflation and increased regulatory activity in 2021.

Note 5 - Capital and Miscellaneous labour for 2021 was higher than 2020 due primarily to higher contract labour for (i) transmission line rebuilds and deficiencies, and (ii) capital distribution work, as well as higher internal labour for capital distribution work.

As part of our review we completed an analysis of the average salary per FTE, including and excluding executive compensation (base salary and short-term incentive). The results of our analysis for 2019 to 2021 are included in the table below:

	Salary Cost Per FTE			
	Actual 2021	**Actual 2020**	**Actual 2019**	**Variance 2021-2020**
Total reported internal labour costs	**$ 69,839**	$ 69,028	$ 66,023	$ 811
Benefit costs (net)	**(10,231)**	(9,563)	(8,926)	(668)
Other adjustments	**(989)**	(1,693)	(1,126)	704
Base salary costs	**58,619**	57,772	55,971	847
Less: executive compensation	**(1,985)**	(1,902)	(1,938)	(83)
Base salary costs (excluding executive)	**$ 56,634**	$ 55,870	$ 54,033	$ 764
FTE's (including executive members)	**607.5**	611.5	616.2	
FTE's (excluding executive members)	**603.5**	607.5	612.2	
Average salary per FTE	**96,492**	94,476	90,833	
% increase	**2.13%**	4.01%	1.48%	
Average salary per FTE (excluding executive members)	**93,842**	91,968	88,261	
% increase	**2.04%**	4.20%	1.10%	

The above analysis indicates that the rate of increase in average salary per FTE excluding executive members for 2021 has decreased from 2020, and 2020 increased from 2019.

The increase in average salary per FTE, including and excluding executive members, increased from 2020 to 2021 by 2.13% and 2.04% respectively. This increase is primarily a result of normal salary inflationary increases and progression.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2019 to 2021 and the targets set for 2021:

Measure	Target 2021	Actual 2021	Actual 2020	Actual 2019
Controllable Operating Costs/Customer	**$ 240.20**	**$ 234.50**	$ 237.70	$ 231.00
Earnings	**$ 43.5M**	**$ 43.8M**	$ 43.2M	$ 42.3M
Cash Flow from Operating Activities	**$ 126.4M**	**$ 148.1M**	$ 136.8M	$ 111.2M
Reliability - Duration of Outages (SAIDI)	**2.50**	**2.48**	2.98	2.34
Customer Satisfaction - % Satisfied	**86.3%**	**88.3%**	87.6%	85.8%
Injury Frequency Rate	**0.74**	**0.56**	0.74	0.37

According to the Company, reliability targets and results exclude interruptions which are Hydro related and those which meet the Institute of Electrical and Electronics Engineers (IEEE) definition of significant events. 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	70%	30%
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 2021 is established as a percentage of base pay for the three employee groups. For 2021, all measures were met in comparison to their targets.

The following table illustrates the target as a percentage of base pay together with the actual STI payouts for 2019 to 2021:

	Target 2021	Actual 2021	Target 2020	Actual 2020	Target 2019	Actual 2019
President	**50%**	**69.77%**	50%	64.44%	50%	70.00%
Executive	**35%-40%**	**51.24%**	35%-40%	46.86%	35% - 40%	50.42%
Directors	**15%**	**20.90%**	15%	19.73%	15%	17.94%

STI actual payout rates for 'President', 'Executive', and 'Directors' employee groups are higher than the prior year. Each payout rate is exceeding targets, consistent with 2020 and 2019.

In dollar terms, the STI payouts for 2019 to 2021 are as follows:

	Actual 2021	Actual 2020	Actual 2019	Variance 2020-2019
President	**$ 277,000**	$ 265,000	$ 287,000	$ 12,000
Executive	**444,000**	402,000	416,000	42,000
Directors	**415,200**	357,800	311,000	57,400
Total	**$ 1,136,200**	$ 1,024,800	$ 1,014,000	$ 111,400
Year over Year % change	**10.87%**	1.07%	16.26%	

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 2021, the non-regulated portion (before tax adjustment) was $414,578 (2020 - $299,085). In 2019 the 'regulatory performance' measure was replaced by the 'cash flow from operating activities' measure where it is included in regulated expense at 100%. In Order No. P.U. 3 (2022), the Board ordered that the recovery of expenses associated with the cash flow component of the corporate target of the Company's STI program be capped at 50% effective January 1, 2022.

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2019 to 2021:

	Base Salary	Short Term Incentive	Other	Total
2021				
Total executive group	$ 1,263,500	$ 721,000	$ 551,501	$ 2,536,001
Average per executive (4)	**$ 315,875**	**$ 180,250**	**$ 137,875**	**$ 634,000**
2020				
Total executive group	$ 1,269,105	$ 632,900	$ 1,339,435	$ 3,241,440
Average per executive (4)	**$ 317,276**	**$ 158,225**	**$ 334,859**	**$ 810,360**
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**
% Average increase 2021 vs 2020	-0.44%	13.92%	-58.83%	-21.76%
Per executive % average increase 2021 vs 2020	-0.44%	13.92%	-58.83%	-21.76%

Base salary for the executive group in 2021 decreased by 0.44% from 2020. In 2021, there was no changeover within the executive positions throughout the year, therefore four executives held positions for the entire year, resulting in four FTE.

Other compensation for the executive group in 2021 decreased from 2020, primarily due to the fact that there was no retention incentive pay required for 2021 as there was in 2020 due to the retiring CEO.

Company Pension Plan

For 2021, we reviewed the accounts supporting the gross charge of $6,966,000 of pension expense for the Company. A detailed comparison of the components of pension expense for 2019 to 2021 is below:

	Actual 2021	**Actual 2020**	**Actual 2019**	**Variance 2021-2020**
Pension expense per actuary	**$ 3,757,000**	$ 4,757,000	$ 639,000	$ (1,000,000)
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**379,000**	402,000	347,000	(23,000)
Group RRSP @ 2%	**307,000**	340,000	314,000	(33,000)
Individual RRSP's	**2,526,000**	2,371,000	2,055,000	155,000
Less: Refunds (net of other expenses)	**(3,000)**	(6,000)	(20,000)	3,000
Total	**$ 6,966,000**	$ 7,864,000	$ 3,335,000	$ (898,000)
Year over year percentage change	**(11.42%)**	135.80%	(10.94%)	

Overall, pension expense for 2021 is lower than 2020 primarily by lower interest costs as a result of a decrease in the discount rate. This is partially offset by an increase in actuarial loss amortization related to the decreased 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 5.7% in 2021.

The employer's portion of the contributions to the Group RRSP is calculated as 2.0% 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 from 6.25% to 6.50% as of January 2021. The closure of the Company's Defined Benefit Plan in 2004 (the Group RRSP (2.0% Plan) also contributed to the increase. New hires are added to the Individual RRSP Plan whereas the majority of retirements are out of the Group RRSP Plan.

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 2019 to 2021 are as follows:

(000's)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Accrued OPEBs	**$ 5,653**	$ 4,191	$ 3,657	$ 1,462
Amortization of transitional balance	**3,504**	3,504	3,504	-
Amount capitalized	**(1,527)**	(1,167)	(920)	(360)
Total	**$ 7,630**	$ 6,528	$ 6,241	$ 1,102

The increase in OPEB's expense from 2020 to 2021 is primarily due to lower amortization of past service credits, partially offset by lower interest costs associated with a decreased discount rate.

Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with Order Nos. P.U. 19 (2003), P.U. 32 (2007), P.U. 43 (2009), and P.U. 13 (2013);
- compared intercompany charges for the years 2020 to 2021 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2021 and investigated any unusual items;
- vouched a sample of transactions for 2021 to supporting documentation;
- assessed the appropriateness of the amounts being charged; and
- reviewed the methodology developed by Fortis Inc. ("Fortis") in 2008 to allocate recoverable expenses to its subsidiaries.

The following table summarizes intercompany transactions from 2019 to 2021 for charges to and from Newfoundland Power:

	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Charges from related companies				
Regulated	**$ 700,744**	$ 220,017	$ 339,937	$ 480,727
Non-Regulated	**2,277,627**	2,587,867	2,360,484	$ (310,240)
Total	**$ 2,978,371**	$ 2,807,884	$ 2,700,421	$ 170,487
Charges to related companies	**$ 235,355**	$ 459,166	$ 1,214,048	$ (223,811)

Fortis bills its recoverable expenses on estimates rather than actual for the first three quarters of each year. Periodically, 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 assets.

We reviewed Fortis'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. As confirmed by the Company, there have been no significant changes to the methodology in 2021. Fortis estimated its net pool of operating expenses for 2021 based on the 2022-2026 business plan and is billed quarterly.

Actual recoverable expenses were determined to be $2,091,000 and are summarized as follows:

2021 Recoverable Expenses from Fortis Inc.

	Amount
Staffing and Staffing Related	$1,353,000
Director Fees and Travel	141,000
Consulting and Legal fees	129,000
Trustee Agent Fees	26,000
Annual Meeting Expenses	47,000
Insurance (D&O)	54,000
Other Costs	294,000
Total Quarterly Billings from Fortis Inc.	2,044,000
Less: 2020 True-Up	(49,000)
Plus: 2021 Q2 True-Up	96,000
	2,091,000
Less amounts previously billed:	
Q1 2021	806,000
Q2 2021	352,000
Q3 2021	536,000
True-Ups	47,000
Q4 2021 balance owing	$ 350,000

According to the Company, 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. Total quarterly billings from Fortis Inc. as shown above were $2,091,000. There were also additional invoices of $839,683 received directly from Fortis during 2021 for total Fortis charges of $2,930,683 ($2,091,000+$839,683), of which $653,056 were regulated and $2,277,627 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, as well as other related parties. The following table summarizes the various components of the regulated intercompany transactions for 2019 to 2021 with Fortis:

(Regulated)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Charges from Fortis Inc.				
Trustee fees and share plan costs	**$ 31,000**	$ 20,000	$ 27,000	$ 11,000
Staff Charges	**60,276**	-	40,884	60,276
Miscellaneous	**561,780**	136,856	208,765	424,924
	$ 653,056	$ 156,856	$ 276,649	$ 496,200
Year over year percentage change	**316.34%**	(43.30%)	(73.88%)	
Charges to Fortis Inc.				
Postage and couriers	**$ 1,501**	$ 1,640	$ 2,181	$ (139)
Staff charges	**75,695**	23,546	51,573	52,149
Miscellaneous	**35,937**	58,704	31,561	(22,767)
	$ 113,133	$ 83,890	$ 85,315	$ 29,243
Year over year percentage change	**34.86%**	(1.67%)	(33.62%)	

The most significant fluctuations from our analysis of regulated charges from Fortis are an increase in the staff charges account of $60,276 and an increase in the miscellaneous account of $424,924. According to the Company, the fluctuation in staff charges is due to a Fortis employee on secondment returning to Newfoundland Power from July to October 2021. The fluctuation in the miscellaneous amount is due to a DC SERP payment of $162,255 paid to an employee upon retirement as well as $258,065 of Microsoft Canada Inc. invoices paid by Fortis on Newfoundland Power's behalf.

The most significant fluctuations from our analysis of regulated charges to Fortis are an increase in staff charges of $52,149 and a decrease in miscellaneous charges of $22,767. The increase in staff charges is due to a Newfoundland Power employee working with the Fortis Operating group and the decrease in miscellaneous charges is because there was a higher-than-normal balance in 2020 from short-term incentive payments relating to employee transfers between Fortis Inc. and Newfoundland Power in 2019.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2019 to 2021:

(Non-Regulated)	**Actual 2021**	**Actual 2020**	**Actual 2019**	**Variance 2021-2020**
Charges from Fortis Inc.				
Director's fees and travel	**$ 135,000**	$ 170,000	$ 178,000	$ (35,000)
Staff charges	**1,438,000**	1,602,000	1,294,000	(164,000)
Miscellaneous	**704,627**	815,867	888,484	(111,240)
	$ 2,277,627	$ 2,587,867	$ 2,360,484	$ (310,240)

Staff charges have decreased from 2020 by $164,000 primarily due to a decrease in non-regulated staff charges from Fortis Inc.

Miscellaneous charges decreased by $111,240. According to the Company this is because of a $97,286 Restricted Share Unit (“RSU”) payment in 2020 that was paid to an employee upon retirement.

The following table provides a summary and comparison of the other intercompany transactions for 2019 to 2021:

Intercompany Transactions (Other)	**Actual 2021**	**Actual 2020**	**Actual 2019**	**Variances 2021-2020**
Charges to Fortis Ontario Inc.				
Staff charges	**$ 2,685**	$ 105,907	$ 390,837	$ (103,222)
Miscellaneous	**48,018**	219,076	326,592	(171,058)
	$ 50,703	$ 324,983	$ 717,429	$ (274,280)
Charges from Fortis Ontario Inc.				
Miscellaneous	**$ -**	$ -	$ 4,875	$ -
Charges to Maritime Electric				
Staff charges	**$ -**	$ 997	$ 276,106	$ (997)
Miscellaneous	**13,780**	36,305	78,496	(22,525)
	$ 13,780	$ 37,302	$ 354,602	$ (23,522)
Charges from Maritime Electric				
Miscellaneous	**$ -**	$ 11,406	$ 6,193	$ (11,406)
Charges to Central Hudson Gas & Electric				
Staff charges	**$ -**	$ -	$ 6,321	$ -
Charges from Central Hudson Gas & Electric				
Miscellaneous	**$ -**	$ 4,068	$ 10,190	$ (4,068)

Intercompany Transactions (Other) Cont'd.	Actual 2021	Actual 2020	Actual 2019	Variances 2021-2020
Charges to Belize Electric Company Ltd.				
Staff charges	**$ 15,599**	$ 12,991	$ 35,226	$ 2,608
Miscellaneous		-	475	-
	$ 15,599	$ 12,991	$ 35,701	$ 2,608
Charges to FortisAlberta Inc.				
Miscellaneous	**$ 9,960**	$ -	$ 5,000	$ 9,960
Charges from FortisAlberta Inc.				
Miscellaneous	**$ 37,612**	$ 37,612	$ 37,612	$ -
Charges to FortisBC Inc./ Fortis BC Holdings				
Miscellaneous	**$ 19,430**	$ -	$ 9,680	$ 19,430
Charges from FortisBC Inc./ FortisBC Holdings				
Miscellaneous	**$ 10,076**	$ 10,075	$ 4,418	$ 1
Charges to Fortis Turks and Caicos				
Miscellaneous	**$ 12,750**	$ -	$ -	$ 12,750

The most significant fluctuations from our analysis of other intercompany charges for 2021 compared to 2020 are as follows:

- Staff charges to Fortis Ontario Inc. decreased by $103,222 in 2021. This decrease was due to a Newfoundland Power employee accepting a position with Fortis Ontario.
- Miscellaneous charges to Fortis Ontario Inc. decreased by $171,058 in 2021. This decrease was due to a short-term incentive payment of $171,666.
- Miscellaneous charges to Maritime Electric decreased by $22,525. This was due to a decrease in RSUs and Performance Share Units (“PSU”) payments of $23,615 from 2020 to 2021.
- Miscellaneous charges to Fortis Alberta Inc. increased by $9,960 in 2021. This increase was due to 2020 Conference Board of Canada charges which were processed in Q1 of 2021.
- Miscellaneous charges to Fortis BC Inc./Fortis BC Holdings increased by $19,430. This increase was also due to 2020 Conference Board of Canada charges which were processed in Q1 of 2021.
- Miscellaneous charges to Fortis Turks and Caicos increased by $12,750 in 2021. This increase was due to the sale and shipment of 200 electric utility meters from Newfoundland Power to Fortis Turks and Caicos.

Loans to Related Parties

The Company entered into short-term borrowing agreements comprised of the following loans to related parties:

Company Name	Amount	Date Funds Advanced	Repayment Date	Amount Repaid *(1)*	Interest Rate	Total Interest Paid
Fortis Inc.	$ 8,000,000	December 8, 2020	January 20, 2021	$ 8,000,000	1.22875%	$ 11,580
Fortis Inc.	$ 10,000,000	January 29, 2021	February 22. 2021	$ 10,000,000	1.17750%	$ 7,742
Fortis Inc.	$ 5,000,000	February 4, 2021	February 22, 2021	$ 5,000,000	1.17750%	$ 2,903
						$ 22,226

(1) Excludes interest paid on loan.

According to the Company, the interest rate is based on the one-month Canadian Dollar Offered Rate (“CDOR”) set on January 29, 2021 and February 4, 2021 plus an 120 bps stamping fee which is the same as the credit facility, minus 24 bps for a standby fee charge which is the unused portion of the credit facility, and an additional discount of 20 bps. The 20 bps is a discount applied to loans to inter-affiliate companies. When an inter-affiliate loan is provided to Newfoundland Power, the same discount of 20 bps is applied. According to the Company, it is verified in all circumstances that the final loan rate is below available market rates, and that loans to and from an affiliate are only executed if it can be shown to be a positive benefit from a customer perspective.

Loans from Related Parties

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

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 2021. It has been confirmed that quarterly reports relating to intercompany transactions have been filed for 2021.

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 2021 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Other company fees				
Other company fees	**$ 3,118**	$ 2,760	$ 3,746	$ 358
Regulatory hearing costs	**1,068**	184	312	884
	$ 4,186	$ 2,944	$ 4,058	$ 1,242
Year over year percentage change	**42.2%**	-27.5%	20.1%	
Deferred regulatory costs				
Total deferred regulatory costs	**$ 353**	$ 353	$ 294	$ -
Year over year percentage change	**0.0%**	20.1%	-13.8%	

Other Company Fee costs for 2021 were higher than 2020. According to the Company, this is primarily due to increased external consultant costs associated with customer energy conservation programs.

Regulatory hearing costs for 2021 were also higher than 2020. This is primarily a result of the Company's 2022/2023 General Rate Application filed on May 27th, 2021, as well as increased costs associated with the 2021 and 2022 Capital Budget Applications.

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 2019 to 2021 is as follows:

(000's)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Miscellaneous	**$ 1,248**	$ 1,459	$ 1,231	$ (211)
Cafeteria and lunchroom Supplies	**39**	48	75	(9)
Promotional items	**99**	88	169	11
Computer Software	**2**	5	3	(3)
Damage claims	**248**	206	278	42
Community relations activities	**-**	1	1	(1)
Donations and charitable advertising	**168**	132	195	36
Books, magazines and subscriptions	**46**	24	18	22
Miscellaneous lease payments	**32**	36	35	(5)
Total miscellaneous expenses	**$ 1,882**	$ 1,999	$ 2,005	$ (118)
Year over year percentage change	**(5.88%)**	(0.30%)	23.84%	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2020 to 2021 these expenses have decreased by 5.88% overall.

Our procedures in this expense category for 2021 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 2021 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with Order No. P.U. 7 (1996-97), the Company filed the 2021 Conservation and Demand Management Report with the Board. This report provided a summary of 2021 CDM activities and costs as well as the outlook for 2022.

In 2021, Newfoundland and Labrador Hydro and Newfoundland Power ("the Utilities") also finalized the joint Five-Year Conservation Plan: 2021-2025 (the "2021 Plan"), which was filed with the Board on December 16, 2020 and continues longstanding CDM programs while also introducing electrification programs. The 2021 Plan focuses on electrification, conservation and demand management activities for the next five years, and features capital investment, program expansion and continued education efforts.

In 2021, CDM programs were implemented by the Utilities in a manner consistent with the 2021 Plan.

A breakdown of CDM costs in 2021 and 2020 is as follows:

($000's)	2021	2020	Variance - 2021-2020
General Costs			
Customer Education and Support	$ 489	$ 429	$ 60
Planning	262	429	(167)
Total General Costs	751	858	(107)
Program Costs			
Insulation Program	1,176	1393	(217)
Thermostat Program	294	324	(30)
HRV Program	205	157	48
Benchmarking Program	974	770	204
Instant Rebates Program	1,020	973	47
Low Income Program	103	0	103
Business Efficiency Program	1,035	1344	(309)
Total Program Costs	4,807	4,961	(154)
Capital Costs			
CDM Capital Expenditures	41	57	(16)
Other Costs			
Curtailable Service Option	403	398	5
Total Costs	$ 6,002	$ 6,274	$ (272)

CDM costs in 2021 totaled $6,002,000 compared to $6,274,000 in 2020, a $272,000 decrease. Conservation costs are lower than in 2020 primarily due to decreased program participation driven by COVID-19 related impacts on local businesses.

In 2021, $4,991,000 ($3,494,000 after tax) in CDM costs were deferred. CDM amortization for 2021 was $5,889,000 (2020- $5,578,000).

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

General Expense Capitalized (GEC)

($000's)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Transfers (GEC)	**(5,276)**	(5,175)	(4,913)	(101)

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 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.

In Order No. P.U. 3 (2022) the Board approved a change in the methodology from capitalizing pension costs from the indirect method via general expenses capitalized to the direct method via labour loader. This change is set to take effect on January 1, 2023.

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 2021 and 2020.

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

($000's)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Vehicle expense	**1,813**	1,725	1,681	88
Operating materials	**1,075**	1,301	1,361	(226)
Inter-company charges	**1,995**	2,277	2,058	(282)
Plants, Subs, System Oper & Bldgs	**3,495**	3,484	3,267	11
Travel	**678**	638	1,142	40
Tools and clothing allowance	**1,143**	1,156	1,289	(13)
Conservation	**1,652**	2,172	2,813	(520)
Taxes and assessments	**1,337**	1,116	1,156	221
Uncollectible bills	**1,111**	2,290	1,980	(1,179)
Insurance	**1,995**	1,698	1,397	297
Severance & other employee costs	**(17)**	126	132	(143)
Education, training, employee fees	**338**	275	444	63
Trustee and directors' fees	**686**	673	518	13
Stationary & copying	**168**	246	257	(78)
Equipment rental/maintenance	**664**	656	790	8
Communications	**2,874**	2,786	2,803	88
Advertising	**1,412**	1,264	1,581	148
Vegetation management	**2,524**	2,306	2,042	218
Computing equipment & software	**2,461**	2,199	1,830	262
Other contract expenses	**5,667**	4,120	4,353	1,547

1. Operating materials for 2021 were lower than 2020 primarily due to lower materials for street light maintenance as a result of the LED Streetlight Replacement program.
2. Intercompany charges for 2021 were lower than 2020 due to lower recoveries from Fortis.
3. Conservation costs for 2021 were lower than 2020 due to lower customer energy conservation rebates and the ongoing review of the 2021 Conservation and Demand Management Plan.
4. Taxes and assessments for 2021 were higher than 2020 due to lower public utilities assessments received on the 2019/20 annual assessment invoice.
5. Uncollectible bills for 2021 were lower than 2020 primarily as a result of improved aging of receivables and improved collection activities.
6. Insurance costs for 2021 were higher than 2020 due primarily to higher premium rates for property insurance.
7. Vegetation management costs for 2021 were higher than 2020 due to additional transmission and distribution vegetation management in 2021.
8. Computing equipment & software costs for 2021 were higher than 2020 due to increases in third party software licensing costs.
9. Other contract expenses include the costs associated with provisioning work from third-party telecommunication companies which increased in 2021 compared to 2020.

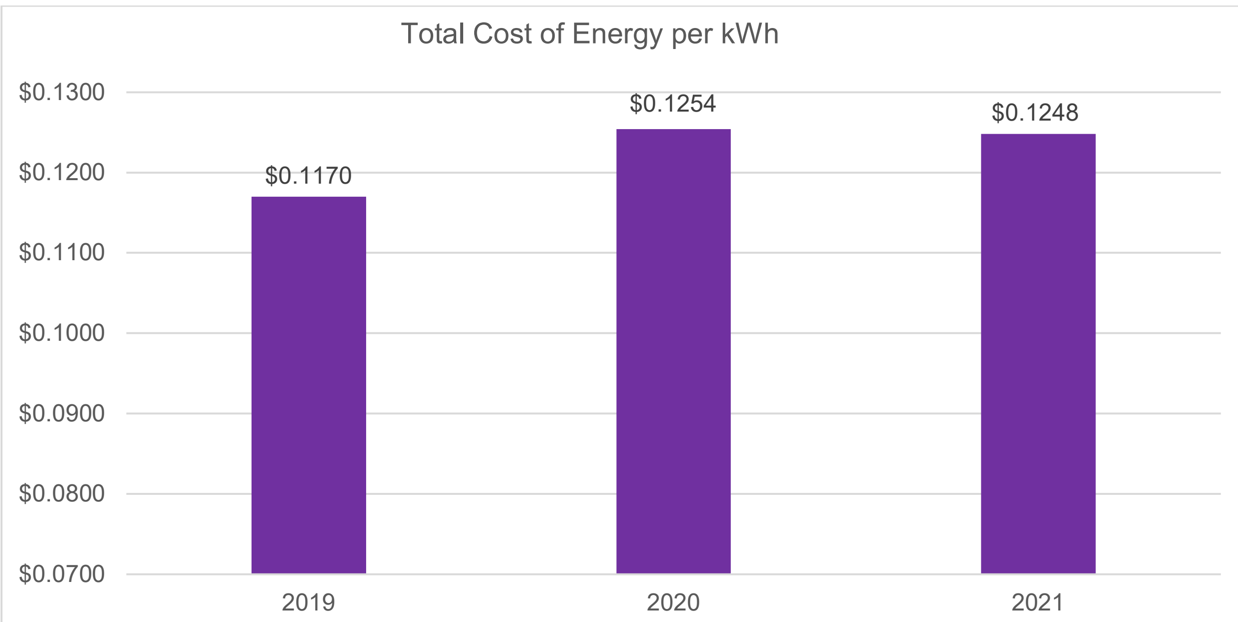
Other Costs

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 2019 to 2021:

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
2019	5,846,600	$79,209	$444,861	$1,752	$68,019	$35,931	$11,299	$42,891	$683,962	$0.1170
2020	5,729,000	$86,844	$468,844	($876)	$71,187	$37,146	$11,893	$43,577	$718,614	$0.1254
2021	**5,715,000**	**$88,150**	**$461,393**	**($876)**	**$73,993**	**$35,311**	**$11,603**	**$43,757**	**$713,331**	**$0.1248**



Purchased Power

We have reviewed the Company's purchased power expense for 2021 and have investigated fluctuations and changes. We performed a recalculation of the purchased power and investigated Hydro bills to ensure that the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro is consistent with the established rates provided and found no errors.

Purchased power expense decreased by $7.5 million, from $468.8 million in 2020 to $461.3 million in 2021. According to the Company, the costs were lower in 2021 primarily due to lower energy purchases and lower electricity system losses.

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 2021 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 2021; and,
- assessed the overall reasonableness of the depreciation for 2021.

Amortization expense for 2021 is $73,993,000 as compared to $71,187,000 for 2020, representing a 3.9% increase. The 2021 and 2020 depreciation expense exclude 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)	**2021**	**2020**	**Variance 2021-2020**	**%**
Depreciation and amortization as reported	**$73,993**	$71,187	$2,806	3.9%
Less: Tax on Cost of Removal (1)	**(6,447)**	(6,205)	(242)	3.9%
Depreciation of Fixed Assets	**$67,546**	$64,982	$2,564	3.9%

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

Depreciation of fixed assets for 2021 is $67,546,000 as compared to $64,982,000 for 2020, representing a 3.9% increase. The change is attributable to an increase of depreciable assets by approximately $83,499,000. The following table provides a comparison of the depreciation of fixed assets for 2021, 2020, and 2019:

(000's)	2021	2020	2019	Variance 2021-2020	Variance 2020-2019
Depreciation of Fixed Assets	**$67,546**	$64,982	$62,066	$2,564	$2,916

Note – A new depreciation study, based on the Company's electric plant as of December 31, 2019 was approved in Order No. P.U. 3 (2022), with effect from January 1, 2022.

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 2021.

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 results of our procedures have been outlined below.

The following table summarizes the various components of finance charges expense for the years 2019 to 2021:

(000's)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Interest				
Long-term debt	**$ 35,450**	$ 36,811	$ 35,375	$ (1,361)
Other	**190**	624	1,384	(434)
Amortization				
Debt discount	**217**	233	235	(16)
Interest charged to construction	**(546)**	(522)	(1,063)	(24)
Total Finance charges	**$ 35,311**	$ 37,146	$ 35,931	$ (1,835)
Year over year percentage change	**(4.94%)**	3.38%	(0.78%)	

The following observations were made with respect to the more significant fluctuations in finance charges:

- There were no new debt issues in 2021 for long-term debt.
- The decrease in long-term debt interest is primarily due to a reduction in average debt in 2021 compared to 2020 due to the repayment of bond issuance series AG of $30,000,000 in October 2020 and annual sinking fund payments on existing debt.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2021 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2021 and have noted that the effective income tax rate decreased from 21.4% in 2020 to 21.0% in 2021. Actual income tax expense in 2021 and 2020 results in the following effective rates:

	2021	2020	2019	2021-2020
Income tax expense	**$ 11,603**	$ 11,893	$ 11,299	$ (290)
Earnings before income tax	**$ 55,360**	$ 55,470	$ 54,190	$ (110)
Effective income tax rate	**21.0%**	21.4%	20.9%	(0.4%)

Income tax expense decreased by $290,000 compared to 2020. The statutory tax rate was 30.0% for both 2021 and 2020.

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 2021 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 $391,149 for the current period compare to a total of $384,831 for the same period during the previous year. According to the Company, the credit total for the 2020-2021 winter season is higher than the previous season total primarily due to variations in Option participant's demand and consumption as well as the mix of Option participants achieving full, partial, or no 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 2021 to prior years and investigated any significant fluctuations;
- reviewed detailed listings of expenses for 2021 and investigated any significant 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 2021	**Actual 2020**	**Actual 2019**	**Variance 2021-2020**
Charged from Fortis Companies	**$ 1,969,435**	$ 2,251,000	$ 2,115,024	$ (281,565)
Performance and restricted share units	**899,513**	1,083,018	665,058	(183,505)
Donations and charitable advertising	**248,294**	210,426	336,662	37,868
Executive short term incentive	**469,303**	576,510	419,479	(107,207)
Miscellaneous	**14,681**	10,934	40,265	3,747
	3,601,226	4,131,888	3,576,488	(530,662)
Less: Income Taxes	**1,080,368**	1,239,566	1,072,946	(159,198)
Total non-regulated (net of tax)	**$ 2,520,858**	$ 2,892,322	$ 2,503,542	$ (371,464)

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 2021, this represents an addition to non-regulated expenses (before tax adjustment) of $469,303 (2020 - $576,510). However, it should be noted that these Orders were issued prior to the replacement of the regulatory performance measure with the cash flow performance measure in 2019; the cash flow measure is included in regulated expense at 100% of target. In Order No. P.U. 3 (2022), the Board ordered that the recovery of expenses associated with the cash flow component of the corporate target of the Company's STI program be capped at 50% effective January 1, 2022. 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 2021 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 2020 and 2021:

(000's)	2021 Actual	2020 Actual	Variance 2021-2020
Regulatory Assets			
OPEBs asset (ii)	**$ 14,016**	$ 17,520	$ (3,234)
Deferred GRA costs (iii)	**-**	353	(353)
Conservation and demand management deferral (iv)	**23,458**	24,356	(898)
Demand management incentive (v)	**1,917**	1,431	486
Employee future benefits (vi)	**21,397**	74,752	(53,355)
Deferred income taxes (viii)	**234,715**	227,450	7,265
	$ 295,503	$ 345,862	$ (50,088)
Regulatory Liabilities			-
Rate stabilization account (i)	**$ 32,466**	$ 22,035	$ 10,431
Cost recovery deferral (ix)	**-**	876	(876)
Weather normalization account (vii)	**2,885**	5,333	(2,448)
Future removal and site restoration provision (x)	**187,622**	178,469	9,153
	$ 222,973	$ 206,713	$ 16,260

(i) 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. On June 17, 2020, in Order No. P.U. 16 (2020), the Board approved a wholesale bill credit of approximately $50.6 million. In Order No. P.U. 17 (2020), the Board approved the one-time bill credit of approximately $47.7 million to eligible customers. This resulted in no change to customer electricity rates effective July 1, 2020.

As of December 31, 2021, there was a refund to customers transferred to the RSA of $25,413,219 related to the Energy Supply Cost Variance Reserve in accordance with Order No. P.U. 32 (2007) and Order No. P.U. 43 (2009).

Pursuant to Order No. P.U. 31 (2010), the Board approved the Company's proposal to create the 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, 2021, the credit balance of $1,419,980 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 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, 2021, the balance of $5,539,105 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 RSA. As of March 31, 2021, $5,333,581 was debited and $5,889,287 was 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 for $1,431,126 as approved in Order No. P.U. 14 (2021).

(ii) Other Post-Employment Benefits

The 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).

(iii) 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. Estimated costs were $1,000,000 with amortization of $353,000 incurred in 2021.

(iv) 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 RSA. The actual costs incurred and deferred at December 31, 2021 were $23,458,000 with amortization of $5,889,287 in 2021.

In Order No. P.U. 3 (2022), the Board approved the amortization of annual costs over 10 years, commencing January 1, 2021 for historical balances and annual charges. The implementation of Order No. P.U. 3 (2022) resulted in a $1,875,000 true-up increase in deferred conservation costs in 2022 relating to annual deferred customer energy conservation program costs incurred up to December 31, 2021.

(v) 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, 2021 was $1,917,000 ($1,342,000 after tax).

(vi) Employee future benefits

On November 10, 2011, the Company submitted an application to the Board requesting approval for the January 1, 2012 adoption of US GAAP for regulatory purposes. On December 15, 2011 pursuant to Order No. P.U. 27 (2011), the Board approved the Company's adoption of US GAAP for general regulatory purposes.

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

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

In Order No. P.U. 27 (2011), the Board ordered that Newfoundland Power *" apply to the Board for approval of changes to existing regulatory assets and liabilities and the creation of any new regulatory assets and liabilities, along with appropriate definitions of the accounts related to these regulatory assets and liabilities, that will be required to effect the adoption of US GAAP".*

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

- 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,
- 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, 2021, the regulated asset for employee future benefits was $21,397,000.

(vii) 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 RSA at March 31st of the following year. In Order No. P.U. 11 (2022), the Board approved the December 31, 2021 net regulatory liability balance in the Weather Normalization Account of $2,885,000 ($2,020,000 net of deferred income tax).

(viii) 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, 2021 was $234,715,000.

(ix) 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 the full amount having been amortized as of December 31, 2021. The net regulating liability for deferred costs – 2019 Cost Recovery Deferral at December 31, 2021 was $Nil.

(x) 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 2021, the balance in this account was $187,622,000 (2020 - $178,469,000).

Based upon our analysis, nothing has come to our attention to indicate that changes in regulatory deferrals for 2021 are unreasonable.

Pension Expense Variance Deferral Account

Scope: ***Review of calculation of the Pension Expense Variance Deferral Account 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 RSA as of the 31st day of March in the year in which the difference arises.

The 2021 PEVDA was calculated at $5,539,106. This balance was transferred to the RSA as a charge on March 31, 2021 in accordance with Order No. P.U. 43 (2009).

We confirm that the 2021 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 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 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 RSA as of the 31st day of March in the year in which the difference arises.

The 2021 OPEBVDA was calculated at $1,419,980. This balance was transferred to the RSA as a charge on March 31, 2021 in accordance with Order No. P.U. 31 (2010).

We confirm that the 2021 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 2021 are as follows:

1. Made capital investments of $109 million of which over 55% were targeted directly to replacing or refurbishing deteriorated and defective equipment.
2. Continued Feeder Upgrades under the "Rebuild Distribution Lines Program".
3. Continued work under the Transmission Line Strategy.
4. Continued the Substation Modernization and Refurbishment program.
5. Continued with the installation of down line reclosers to provide for improved control of the distribution system along with improving the ability to locate and isolate system trouble.
6. Began collaboration with the Electric Power Research Institute ("EPRI") to test drones as an innovative solution for transmission and distribution line inspections. Using drones has the potential to improve safety, increase inspection quality and reduce costs over the long-term.
7. Began implementation of electronic logging devices on all heavy fleet vehicles. These are typically used in commercial motor vehicles to record driving time and hours of service automatically, as well as to capture data on the vehicle's engine, movement and distance driven. The new system, from GeoTab, will replace the Company's existing Record of Duty and Truck Inspection forms, in compliance with current federal and provincial regulations. It will also be leveraged to provide future benefits such as tracking vehicle idling time and reducing fuel costs, assessing driver behavior to improve safety and analyzing fleet data to improve operational efficiency and fleet availability.
8. Completed development of a Climate Adaptation Plan and Clean Energy Plan. The Plan details a strategy to manage and prepare for the impacts of climate change including extreme wind, ice and snowstorms, flooding and wildfires.
9. Completed the initial installation of hardware for a pilot of smart-city street lighting in Mount Pearl. The pilot project utilizes dynamic lighting controllers and radar sensors to provide traffic data. Software installation and security measures are in progress, and provision of tailored reports for the city began in the first quarter of 2022.
10. Upgrades to the Company's Geographic Information System and Outage Management System were completed in 2021. The upgrades will ensure both systems function in a reliable and stable manner, are fully supported by the vendor and will also provide several improvements, such as enhanced tracking of incidents of wires down when there is no power outage.
11. Integrated the Outage Management System with the Geographical Information System providing for more accurate and precise analysis of outage data.
12. Implemented a 6-year program to replace all HPS street light fixtures with LED fixtures. The program will result in lower customer rates as a result of lower energy and maintenance costs for LED streetlights. LED streetlights also provide more reliable and better quality lighting for customers.

13. Provided web-based access to contractor owned vehicles and computers. This is particularly useful for assigning work.

14. Work concluded on revising core safety code training to be delivered to employees, including developing new testing procedures to ensure comprehension and ability to apply core safety code principles.

15. Engaged an industrial psychologist to develop training for operational employees aimed at increasing situational awareness and avoiding distractions to stay focused safely on work tasks. The program gives employees techniques to increase their attention span and ability to focus, problem solve and manage stress, emotions and improve their overall mental health.

16. Collaborated with HSE Integrated Ltd. to develop fall protection training specific to Power Line Technicians.

17. Held firefighter and first responder electrical safety seminar and in-class school presentations. The Company reached a total of 888 students in 2021 through the Youth Electrical Safety program.

18. Initiatives aimed at improving safety performance this year included tracking of new quality leading indicators. In particular these target the quality of completed work and completed tailboard discussions.

19. New applications of Geographic Information Systems ("GIS") technology were implemented to enable safer back country travel to access transmission lines. A project was started to map safe off-road routes for accessing and travelling transmission line rights-of-way. The new maps identify nearby water bodies and hazards such as bog holes and steep inclines and the safe routes will guide travel on snowmobiles, ATVs and other off-road equipment.

20. Implemented a new internet-based service that allows an agent to validate customer identification remotely, online or over the phone. eIDverifier, a service offered by Equifax, has resulted in a lower fraud risk factor and decreased email volumes while providing improved and least cost service delivery.

21. Newfoundland Power and Bell are working together to improve the customer experience related to vegetation management requests, specifically in areas where Bell is responsible for this service. Newfoundland Power now completes all customer-requested vegetation control in these areas, utilizing the Company's customer contact center, field staff and contractors. Related costs are billed back to Bell. Improved service consistency and responsiveness is anticipated to relieve frustration expressed by customers in recent years.

22. A number of enhancements were made to the Company's customer satisfaction monitoring. A new dashboard was completed that allows improved access to customer satisfaction data. Rather than wait for quarter end to receive customer survey results, interim results are available throughout the quarter using the new dashboard. This provides early insight into customer satisfaction, allowing the Company the opportunity to make improvements.

23. The procurement phase of the CIS replacement project is nearing completion. A software vendor was selected through the request for proposal process in 2021 and negotiations with the vendor were successfully concluded. A contract has been signed with Oracle Corporation for the majority of the software components of the Customer-to-Meter CIS solution.

24. In response to a number of telecommunications network outages over the past year, the Company expanded its business continuity infrastructure by adding 12 new backup hard-wired phone lines for its customer contact centre. This expansion now allows for a total of 20 phone lines for agents to receive calls outside the interactive voice response system in the event of a network outage.

25. The Company continued to support its customers in 2021 by allowing outstanding bills to be paid on more flexible payment terms.

26. Customer email traffic grew by 27% in 2021, to over 167,000 emails received. To ensure quality customer service delivery, Newfoundland Power continues to survey customers to obtain feedback on their email transaction experience.
27. A new dashboard was implemented to provide improved awareness of outstanding customer accounts by location. Using the new dashboard, field services staff deployment can be prioritized based on customers' account status and amounts owing and organized by geographic location.
28. A new key accounts program was launched targeting larger commercial customers (rate class 2.3 and 2.4). The program is meant to add value for these customers by improving service delivery and offering more personalized service to help meet their needs. As part of the program, the first edition of the quarterly What's Happening newsletter was distributed to over 950 commercial customers.
29. Regular phishing security tests were conducted throughout the year. Employee phishing training and testing results were above industry peer results. Newfoundland Power had an average pass rate of 99.1%, compared to the industry average of 95.3%.
30. The Company's perimeter (internet) firewall and SCADA firewalls were replaced. This initiative increases Newfoundland Power's ability to detect threats in network traffic.
31. Work was completed on segmenting backup infrastructure and restricting access with a new Privileged Access Management system. This safeguards backup systems in the event that the main systems become compromised.
32. Installation of new vulnerability management software, which provides automated scanning and reporting of cybersecurity vulnerabilities on the Company's network.
33. takeCHARGE partnered with four local associations to deliver a webinar series raising awareness of electric vehicles ("EVs"). Over 80 members from Hospitality Newfoundland and Labrador, the NL Construction Association, the NL Environmental Industry Association and the Canadian Home Builders' Association NL tuned in to get up to speed on EVs in the province.
34. Implementation of an upgrade to cloud based Itron Mobile technology to read meters was completed. Each meter reading vehicle can read up to 100,000 meters in one day and return the information remotely from the field. This technology innovation allows Newfoundland Power to collect more data at a faster rate, improves operating efficiencies, and provides better service to customers by reducing meter reading estimates and the need to access customer properties.
35. A project was launched to study the potential distribution system impacts from increased EV load, in partnership with software vendor Opus One Solutions.
36. The 10th annual takeCHARGE of your Town Challenge received 40 proposals from municipalities across the province on ways to make their communities more energy efficient.
37. A new e-recruitment and on-boarding module for its VIP human resources management system was implemented. This module provides a collaborative workspace for recruiting, with increased transparency and communication for the hiring manager. It also centralizes all related documentation and approvals and provides initial screening to more easily identify a short list of the top applicants.
38. Inclusive Leader training was delivered to all of the Company's 93 managers and supervisors, in partnership with the Women In Resource Development Corporation ("WRDC"). Topics included elements of diversity and unconscious bias. Over 85% of non-supervisory employees have also participated in Inclusion and Diversity ("I&D") awareness sessions delivered online and in-person.

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 2019	Actual 2020	Actual 2021	Plan 2021	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1]	2.34	2.98	2.48	2.50	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply[1]	1.62	2.35	1.96	1.73	No
	Plant Availability (%)	95.7	96.8	96.0	95.0	Yes
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	85.8	87.6	88.3	86.3	Yes
	Call Centre Service Level (% per second)[2]	77/60	81/60	81/60	80/60	Yes
	Trouble Call Responded to Within 2 Hours (%)	81.0	80.0	86.0	85.0	Yes
Safety	All Injury/Illness Frequency Rate	0.4	0.7	0.6	0.7	Yes
Financial	Earnings (millions)[3]	$42.3	$43.2	$43.8	$43.5	Yes
	Gross Operating Cost/Customer[4]	$229	$235	$233	$241	Yes

[1] 2019 statistics exclude the impact of a wind storm in February, Hurricane Dorian in September and a snow storm in November. 2020 statistics exclude a January storm and Snowmageddon. 2021 statistics exclude a January storm, Hurricane Larry, and a December storm.
[2] Service level is based on calls answered in 60 seconds.
[3] Earnings applicable to common shares.
[4] Excluding conservation program costs, employee future benefit costs, and non-regulated expenses.

The following table compares whether the Company measures were achieved during the 2019, 2020, and 2021 years:

Category	Measure	Measure Achieved 2019	Measure Achieved 2020	Measure Achieved 2021
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply	Yes	No	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply	Yes	No	No
	Plant Availability (%)	Yes	Yes	Yes
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	Yes	Yes	Yes
	Call Centre Service Level (% per second)	No	Yes	Yes
	Trouble Call Responded to Within 2 Hours (%)	No	No	Yes
Safety	All Injury/Illness Frequency Rate	Yes	Yes	Yes
Financial	Earnings (millions)	Yes	Yes	Yes
	Gross Operating Cost/Customer	Yes	Yes	Yes