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1.0. Background

This report details the method used by Newfoundland Power Inc. ("Newfoundland Power" or the "Company") to forecast its test year full-time equivalents ("FTEs") and labour expense. In addition, it describes the assumptions used to determine forecast vacancies.[1]

Following completion of the Customer Service System ("CSS") Replacement Project, the Company's labour requirements are forecast to be consistent over the test years.[2] In managing its workforce, the Company matches overall capacity and capability with anticipated work requirements.

The method used to forecast labour requirements and FTEs for a test year reflects this basic workforce management philosophy.

2.0 Forecasting Workforce Requirements

2.1 Forecasting the Work

The starting point in forecasting Newfoundland Power's annual labour requirements is the Company's annual capital and operational work requirements.[3]

Annual capital work requirements are principally based on specific expenditures required to replace deteriorated, defective or obsolete equipment, and to serve forecast customer growth.[4]

Annual operating work requirements are principally focused on the maintenance and operation of the electrical system, response to customer enquiries, and commercial functions such as meter reading and billing.[5] These requirements tend to be stable over time. For this reason, historical expenditures, adjusted for changes in operating requirements, are the foundation for forecasting annual operating work requirements.

2.2 Workforce Options

Having determined the annual work requirements, the Company considers the amount of internal labour available to meet these requirements.

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1 In Order No. P.U. 32 (2007), the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") directed Newfoundland Power to include this information as part of its next general rate application.

2 For the period of 2023F through 2026F, Newfoundland Power's workforce is forecast to decrease by 3.5%, or 23.0 FTEs. This decrease is related to the completion of CSS in 2023.

3 In addition to capital and operating requirements, there are labour requirements for rechargeable and recoverable items. These items include labour associated with material handling (i.e. stores) and vehicle service centre labour costs, which are recharged as overheads on operating and capital work. It also includes customer jobbing, third-party provisioning services, and inter-affiliate labour charges.

4 These requirements are approved by the Board on a prospective basis each year through the Company's capital budget applications.

5 Annual operating work requirements also include general support functions, such as information services, human resources, and finance.

The Company meets its annual work requirements using a combination of employees, temporary employees and contractors. This approach permits Newfoundland Power to maintain a highly skilled core workforce and reasonable flexibility to respond to variations in work requirements on a least-cost basis.

Annual capital work requirements are typically met through a combination of the Company's internal workforce and contractors. This is partly attributable to the variable nature of these work requirements.[6] It is also consistent with the deployment of the Company's internal workforce.[7]

Annual operating work requirements tend to be met by the Company's internal workforce. This is attributable to stability of these work requirements on a year over year basis,[8] and the specialized nature of these work requirements.[9]

2.3 Vacancy Assumptions

In determining the internal workforce available to execute the annual capital and operating work requirements, the Company assesses its internal workforce on an FTE basis.[10]

The 2023 FTE forecast provides the basis for forecasting FTE requirements for 2024 through 2026. Newfoundland Power makes adjustments for future years, 2024 to 2026, to better predict availability of the internal workforce to meet work requirements. This, in turn, permits the Company to assess its workforce options.[11]

Typical adjustments to an FTE forecast include anticipated retirements, leaves of absence, terminations and new hires.[12] These adjustments reflect the timing and salary impacts of workforce changes. For example, in the case of retirements, differences in salary and timing gaps

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6 Annual capital work requirements differ depending on the projects involved. For example, penstock construction requires riggers and welders, skilled trades not typically employed by the Company. Accordingly, such work would be performed by contractors.

7 For example, the deployment of Powerline Technicians ("PLTs"). PLTs perform a mixture of operating and capital maintenance. In winter, Newfoundland Power's service obligations practically require it to have PLTs deployed throughout its service territory in sufficient numbers to respond to seasonal electrical system trouble. In the construction season, PLTs can be deployed to construction sites across the province, as necessary.

8 Approximately 4% of Newfoundland Power's internal workforce is temporary labour. Use of temporary labour provides operating flexibility.

9 Specialized knowledge of electrical system operations is required for operational work and is therefore a core competency of Newfoundland Power's workforce. This specialized knowledge is not typically required for the majority of the Company's capital work requirements.

10 Newfoundland Power calculates FTEs based on employee hours worked divided by total working hours in a year. For approximately 49% of the workforce, the total working hours in a year are 2,080. For the remainder, the total working hours in a year are 1,950. The FTE calculation reflects only hours worked and permits a better matching of work requirements to available workforce options than forecasting positions and applying a vacancy allowance.

11 From a practical perspective, forecast FTEs will become the basis for the Company's determination of hiring requirements and contract labour requirements.

12 Leaves of absence include maternity leave, absences due to long-term disability or workplace injury, education leave and other leaves of absence approved by the Company.

or overlaps among employees entering and leaving the workforce can be incorporated.[13] A similar approach is used for employees commencing leaves of absence and those returning from leave.

Adjustments are fully reflected in both forecast FTEs and labour costs. Forecast FTEs are a tool to assess the *internal* workforce available to meet overall work requirements. Forecast labour costs reflect salary and timing differences associated with changes in the internal workforce.

Newfoundland Power's assessment of its internal workforce is undertaken in the context of its total forecast labour requirements. Total labour requirements are a function of forecast capital and operating work requirements.[14]

2.4 Reconciling Work and Labour

Newfoundland Power's total forecast labour requirements for 2023 is $91.9 million. For 2024, 2025 and 2026, the total forecast labour requirements are $92.4 million, $95.7 million and $99.3 million, respectively. These requirements reflect forecast capital and operational work requirements for each year and include internal labour and contract labour.

The Company's forecast internal labour expense for 2023 is $75.4 million. For 2024, 2025 and 2026, forecast internal labour expense is $75.5 million, $78.5 million and $81.9 million, respectively. The difference between the total forecast labour requirements and the Company's available internal labour will be addressed using contract labour.

3.0 2024 to 2026 Labour Forecasts

3.1 2024 FTEs and Internal Labour Expense

The 2024 FTEs and internal labour expense were calculated using the 2023 FTE forecast as the starting point. In 2023, the number of FTEs is forecast to be 655.0. The associated internal labour expense is forecast to be $75.4 million. To account for the impact of inflation, the 2023 internal labour expense is adjusted to reflect forecast salary increases applicable to 2024.

The 2024 labour forecast reflects an overall decrease of 23 FTEs, primarily due to reduction in labour following the completion of the CSS Replacement Project. FTEs and internal labour expense in 2024 also include employees that are forecast to work a partial year in 2023, but are anticipated to be in the workforce for a full year in 2024, partially offset by employees who left in 2023.

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[13] The time period between employees entering and leaving the workforce can be either negative or positive. For example, if a replacement employee arrives before a senior employee retires to avail of a training opportunity, this will increase the FTE count and labour expense. However, if there is a period of time a position remains vacant awaiting a replacement employee to enter the workforce, this will decrease the FTE count and labour expense.

[14] The loss of an employee in any year will typically result in the work being performed by temporary labour or a contractor. It is unusual that either capital or operating work would not be performed in any given year due to the loss of an employee.

Schedule A presents the detailed breakdown of forecast internal labour expense and FTEs for 2024.

3.2 2025 FTEs and Internal Labour Expense

The 2025 FTEs and internal labour expense were calculated using the 2024 forecast as the starting point. To account for the impact of inflation, the 2024 internal labour expense is adjusted to reflect forecast salary increases applicable to 2025.

The 2025 test year labour forecast reflects an overall increase of 1.0 FTE.

Schedule B presents the detailed breakdown of forecast internal labour expense and FTEs for 2025.

3.3 2026 FTEs and Internal Labour Expense

The 2026 FTEs and internal labour expense were calculated using the 2025 forecast as the starting point. To account for the impact of inflation, the 2025 internal labour expense is adjusted to reflect forecast salary increases applicable to 2026.

The 2026 test year labour forecast reflects an overall decrease of 1.0 FTE.

Schedule C presents the detailed breakdown of forecast internal labour expense and FTEs for 2026.

Schedule A
2024 Internal Labour Forecast

	Labour Expense ($000s)	FTEs	Notes
2023 Workforce			
Operating	35,485		1
Capital	30,019		
Rechargeable & Recoverable	9,852		
Total	**75,356**	**655.0**	2
2024 Salary Increase	**2,864**		3
Two Extra Work Days in 2024	**602**		4
Adjustments for 2024			
2024 Retirements			
Employee Retirement[15]	(1,651)	(11.5)	5
Retirement Replacement	1,315	10.5	6
2024 Leaves of Absence			
Employees Taking Leave	(869)	(7.0)	7
Employees Returning from Leave	467	4.0	8
Terminations	(3,068)	(22.7)	9
New Hires	241	2.0	10
Partial Year Adjustments[16]	207	1.7	11
2024 Adjusted Workforce	**75,464**	**632.0**	12
2024 Workforce			
Operating	36,790		
Capital	28,368		
Rechargeable & Recoverable	10,306		
Total	**75,464**		13

[15] Retirement estimates are based on employees reaching age 65, or reaching age 60 with the combination of 95 years of age plus service, or have expressed interest in retiring prior to reaching this milestone.

[16] Partial year adjustments include FTE and labour adjustments necessary to account for employees who started or resumed their employment in 2024. These employees do not account for full annual salaries in the 2023 labour expense or for full FTEs in 2023. These adjustments also include employees who left the Company in 2023. These employees do not account for full annual salaries in the 2024 labour expense or full FTEs in 2024.

Notes for Schedule A

No.	Description
1	The operating labour cost forecast for 2023. It includes the impact of all retirements, leaves of absence, terminations and new hires expected for 2023.
2	The 2023 forecast FTEs are reflective of the anticipated 2023 work requirement. It reflects the impacts, including timing, of retirements, leaves of absence, terminations, and new hires of regular and temporary employees in 2023. Total labour expense includes payroll loading.
3	The 2024 salary increase is based upon a weighted average salary increase of 3.80%.
4	In 2024, there are 262 work days versus 260 in 2023, resulting in a labour increase of $602,000.
5	In 2024, there are 22 employees expected to retire. The 2024 labour cost reduction for retirements is $1,651,000. The 2024 reduction in FTEs of 11.5 reflects the timing of the forecast retirements.
6	Twenty-two of the retiring employees will be replaced in 2024, which results in a $1,315,000 labour cost increase and a 10.5 FTE increase for 2024.
7	In 2024, the Company forecasts 11 employees taking leaves of absence based on past experience and known circumstances. The 2024 labour reduction for leaves is $869,000, with a corresponding FTE reduction of 7.0.
8	In 2024, the Company forecasts seven employees returning from leaves of absence based on past experience and known circumstances. The 2024 labour increase for employees returning from leave is $467,000, with a corresponding FTE increase of 4.0.
9	In 2024, the Company forecasts a labour decrease of $3,068,000, with a corresponding FTE decrease of 22.7 due to the completion of the CSS Replacement Project.
10	In 2024, the addition of four new hires for PLT Apprentices is expected to increase FTEs by 2.0 and labour costs by $241,000.
11	The 2024 labour increase for partial year adjustments is an increase of $207,000, with a corresponding FTE increase of 1.7.
12	The 2024 forecast FTE count.
13	The 2024 forecast labour cost, excluding overtime.

Schedule B
2025 Internal Labour Forecast

	Labour Expense ($000s)	FTEs	Notes
2024 Forecast Workforce			
Operating	36,790		1
Capital	28,368		
Rechargeable & Recoverable	10,306		
Total	**75,464**	**632.0**	2
2025 Salary Increase	**3,358**		3
Extra Work Day in 2024	**(301)**		4
Adjustments for 2025			
2025 Retirements			
Employee Retirement[17]	(931)	(6.5)	5
Retirement Replacement	685	5.5	6
2025 Leaves of Absence			
Employees Taking Leave	(900)	(7.0)	7
Employees Returning from Leave	769	6.0	8
New Hires	258	2.0	9
Partial Year Adjustments[18]	126	1.0	10
2025 Adjusted Workforce	**78,528**	**633.0**	11
2025 Forecast Workforce			
Operating	38,278		
Capital	29,576		
Rechargeable & Recoverable	10,674		
Total	**78,528**		12

[17] Retirement estimates are based upon employees reaching age 65, or reaching age 60 with the combination of 95 years of age plus service.

[18] Partial year adjustments include FTE and labour adjustments necessary to account for employees who started or resumed their employment in 2025. These employees do not account for full annual salaries in the 2024 labour expense or for full FTEs in 2024. These adjustments also include employees who left the Company in 2024. These employees do not account for full annual salaries in the 2025 labour expense or for full FTEs in 2025.

Notes for Schedule B

No.	Description
1	The operating labour cost for 2024. It includes the impact of all retirements, leaves of absence, terminations and new hires in 2024.
2	The 2024 forecast FTEs are reflective of the 2024 work requirement. It reflects the impacts, including timing, of all retirements, leaves of absence, and new hires of regular and temporary employees in 2024. Total labour expense includes payroll loading.
3	The 2025 salary increase is based upon a weighted average salary increase of 4.45%.
4	In 2025, there are 261 work days versus 262 in 2024, resulting in a labour decrease of $301,000.
5	In 2025, there are 11 employees expected to retire. The 2025 labour cost reduction for retirements is $931,000. The 2025 reduction in FTEs of 6.5 reflects the timing of the forecast retirements.
6	Eleven of the retiring employees will be replaced in 2025, which results in a $685,000 labour increase and a 5.5 FTE increase for 2025.
7	In 2025, the Company forecasts nine employees taking leaves of absence based on past experience. The 2025 labour reduction for leaves is $900,000, with a corresponding FTE reduction of 7.0.
8	In 2025, the Company forecasts 10 employees returning from leaves of absence based on the 2024 forecast. The 2025 labour increase for employees returning from leave is $769,000, with a corresponding FTE increase of 6.0.
9	In 2025, the addition of four new hires for PLT Apprentices is expected to increase FTEs by 2.0 and labour costs $258,000.
10	The 2025 labour increase for partial year adjustments is $126,000, with a corresponding FTE increase of 1.0.
11	The 2025 forecast FTE count.
12	The 2025 forecast labour cost, excluding overtime.

Schedule C
2026 Internal Labour Forecast

	Labour Expense ($000s)	FTEs	Notes
2025 Forecast Workforce			
Operating	38,278		1
Capital	29,576		
Rechargeable & Recoverable	10,674		
Total	**78,528**	**633.0**	2
2026 Salary Increase	**3,534**		3
Adjustments for 2026			
2026 Retirements			
Employee Retirement[19]	(687)	(4.5)	4
Retirement Replacement	611	4.5	5
2026 Leaves of Absence			
Employees Taking Leave	(951)	(7.0)	6
Employees Returning from Leave	551	4.0	7
Terminations	(129)	(1.0)	8
New Hires	273	2.0	9
Partial Year Adjustments[20]	131	1.0	10
2026 Adjusted Workforce	**81,861**	**632.0**	11
2026 Forecast Workforce			
Operating	39,910		
Capital	30,873		
Rechargeable & Recoverable	11,078		
Total	**81,861**		12

[19] Retirement estimates are based upon employees reaching age 65, or reaching age 60 with the combination of 95 years of age plus service.

[20] Partial year adjustments include FTE and labour adjustments necessary to account for employees who started or resumed their employment in 2026. These employees do not account for full annual salaries in the 2025 labour expense, nor would they have accounted for full FTEs in 2025. These adjustments also include employees who left the Company in 2025. These employees do not account for full annual salaries in the 2026 labour expense, nor would they account for full FTEs in 2026.

Notes for Schedule C

No.	Description
1	The operating labour cost for 2025. It includes the impact of all retirements, leaves of absence, and new hires in 2025.
2	The 2025 forecast FTEs are reflective of the 2025 work requirement. It reflects the impacts, including timing, of all retirements, leaves of absence, terminations, and new hires of regular and temporary employees in 2025. Total labour expense includes payroll loading.
3	The 2026 salary increase is based upon a weighted average salary increase of 4.50%.
4	In 2026, there are nine employees expected to retire. The 2026 labour cost reduction for retirement is $687,000. The 2026 reduction in FTEs of 4.5 reflects the timing of the forecast retirements.
5	Nine of the retiring employees will be replaced in 2026, which results in an $611,000 labour increase and a 4.5 FTE increase for 2026.
6	In 2026, the Company forecasts nine employees taking leaves of absence based on past experience. The 2026 labour reduction for leaves is $951,000, with a corresponding FTE reduction of 7.0.
7	In 2026, the Company forecasts nine employees returning from leaves of absence based on the 2025 forecast. The 2026 labour increase for employees returning from leave is $551,000, with a corresponding FTE increase of 4.0.
8	In 2026, the Company forecasts an FTE reduction of 1.0 as a result of the conclusion of the Load Research and Rate Design Review. This will result in a labour reduction of $129,000.
9	In 2026, the Company forecasts four new PLT Apprentices. The 2026 labour increase for new hires is $273,000, with a corresponding FTE increase of 2.0.
10	The 2026 labour increase for partial year adjustments is $131,000, with a corresponding FTE increase of 1.0.
11	The 2026 forecast FTE count.
12	The 2026 forecast labour cost, excluding overtime.

2025 and 2026 Rate Base Allowances

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1.0 Introduction

It is common practice for a utility's rate base to include allowances for: (i) funds used during construction ("AFUDC"); (ii) cash working capital ("CWC Allowance"); and (iii) materials and supplies ("Materials Allowance").[1]

For this Application, Newfoundland Power Inc. ("Newfoundland Power" or the "Company") has reviewed its CWC Allowance and Materials Allowance to reflect any changes that have occurred since the last detailed review.[2]

The CWC Allowance calculated for 2025 and 2026 is $1,475,000 and $1,711,000, respectively. This is approximately 0.2% of forecast 2025 regulated cash operating expenses and approximately 0.3% of forecast 2026 regulated cash operating expenses.[3]

The Materials Allowance calculated for 2025 and 2026 is $15,180,000 and $15,422,000, respectively. This reflects a revised expansion factor for the calculation of expansion inventory of 13.27%.[4]

2.0 CWC Allowance

2.1 Methodology

The inclusion of a CWC Allowance in rate base, and the use of a lead/lag study to calculate the allowance, are accepted practices for regulated utilities. A lead/lag study recognizes that a utility provides service to customers prior to the receipt of payment for that service. It also recognizes that there is generally a delay in payment by the utility for the goods and services it acquires.

A lead/lag study analyzes transactions over a period of time to determine: (i) for each revenue stream, the average number of lag days between the provision of service to customers and the receipt of payment for that service from customers (the "revenue lags"); and (ii) for each expense, the average number of lag days between the provision of service to customers and the date that the utility pays for the goods and services that it acquires to provide service (the "expense lags"). The difference between these two lags is referred to as a "net lag" or "net lead."

A net lag occurs when the payment of an expense precedes the collection of its related revenue stream. In this situation, the utility's investors must supply capital to finance the expense until receipt of the related revenue. A net lead position occurs in the opposite situation and has the opposite impact.

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1 Newfoundland and Labrador Hydro's ("Hydro") rate base includes these three allowances in addition to a fuel inventory allowance.

2 The last CWC Allowance and Materials Allowance review was completed for the Company's *2022/2023 General Rate Application* and formed part of the settlement agreement reached in relation to that application.

3 This compares to $6,548,000 and $6,800,000, or 1.1% and 1.2% of forecast regulated cash operating expenses, used in 2022 and 2023, respectively. See *Section 2.2* of this report for further detail.

4 This compares to a Materials Allowance of $8,756,000 and $8,905,000, which included an expansion factor of 19.08%, used in 2022 and 2023, respectively.

Once the revenue and expense lags are determined, the CWC Allowance is calculated as follows:

(i) Weight each revenue lag by its related revenue stream to calculate the total weighted average revenue lag.
(ii) Weight each expense lag by its related expense to calculate the total weighted average expense lag.
(iii) Subtract the weighted average expense lag from the weighted average revenue lag and divide the result by 365 days. This is the cash working capital factor ("CWC Factor").[5]
(iv) Multiply the CWC Factor by the total regulated expenses to calculate the average amount of working capital required to finance the expenses.
(v) Add the amount determined in step (iv) to the net impact of the collection and payment of the harmonized sales tax ("HST") on working capital. The result is the CWC Allowance.

The CWC Allowance determined through a lead/lag study is indicative of a utility's average daily working capital requirements.

2.2 Leads and Lags: 2025 and 2026

General

In determining its 2025 and 2026 forecast cash working capital allowance, each of the individual revenue and expense lags were reviewed and updated to reflect any observed changes in revenue/expense streams. In addition, the timing and remittance of HST payments were also reviewed and updated.

Newfoundland Power's lead/lag study is based on 2022 actual data as it represents the most recent historical results available at the time. There have been no material changes to the Company's billing and collection procedures or to its payment procedures since 2022. In addition, there are no material changes forecast for the 2025 and 2026 test years.

Through the lead/lag study, Newfoundland Power has determined: (i) its revenue lags; (ii) its expense lags; and (iii) the leads/lags associated with HST for 2025 and 2026 test years. Together, these leads and lags form the basis for the 2025/2026 CWC Allowance.

The leads and lags calculated have been applied to the Company's forecast 2025 and 2026 test year data to calculate the proposed CWC Allowance. These calculations are summarized on the following page.

5 In a net lag situation, the CWC Factor represents the percentage of expenses that has to be financed by the utility's investors during the year. Investor funding is necessitated by the fact that the cash outflows for expenses preceded the cash inflows for the related revenues. The CWC Allowance for a net lag is added to the rate base in order to provide a utility with a reasonable opportunity to recover the cost of the related investor-supplied funding. In a net lead situation, the opposite is true.

Revenue Lag

The revenue lag was calculated by analyzing all of the Company's revenue streams and accounts receivable for 2022 to determine the average number of lag days between when service is provided to customers and when payment for the service is received from customers.

Newfoundland Power has two distinct revenue streams which can broadly be described as "consumer billings" and "other billings."

Consumer billings included in the calculation of the CWC Allowance are composed of: (i) electricity billings and related municipal tax billings; (ii) forfeited discounts and interest earned on overdue accounts receivable; (iii) ancillary items such as connection/reconnection fees; and (iv) HST.

Other billings are composed of: (i) pole rentals; (ii) work done by the Company for others; (iii) various miscellaneous revenues; and (iv) HST.

Revenue lags were calculated for consumer billings and other billings. These were weighted, based on the percentage of the total 2025 and 2026 forecast billings represented by each, to produce a total weighted average revenue lag of 31.48 days for 2025 and 31.43 days for 2026.[6] Revenue lags are set out in Schedule 1 of Appendices A and B.

For 2025 and 2026, the revenue lag associated with the collection of consumer billings decreased compared to the 2022/2023 lead/lag study. In determining the lag days, the accounts receivable balance was analyzed and the average monthly balance has decreased from 2020 to 2022.

Expense Lag

The expense lag was calculated by analyzing each of the Company's cash operating expenses for 2022 to determine the average number of lag days between when service is provided to customers and when payment is made for the goods and services that are acquired to provide service.[7]

The calculated expense lag of each cash operating expense was weighted based on the percentage of the total 2025 and 2026 forecast cash operating expenses represented by each to produce a total weighted average expense lag for the Company of 29.78 days for 2025 and 29.38 days for 2026.[8] These are set out in Schedule 2 of Appendices A and B.

For 2025 and 2026, the expense lag associated with the payment of corporate income taxes has decreased compared to the 2022/2023 lead/lag study. In determining the expense lag for

6 By comparison, the revenue lag included in the 2022 and 2023 test year cash working capital study was 35.45 days for 2022 and 35.49 days for 2023.

7 The general expenses capitalized ("GEC") lead/lag days for 2022 were adjusted to incorporate the changes to the GEC calculation approved in Order No. P.U. 3 (2022) as part of Newfoundland Power's *2022/2023 General Rate Application*.

8 By comparison, the expense lag included in the 2022 and 2023 test year cash working capital study was 31.30 days for 2022 and 31.11 days for 2023.

corporate income taxes, the actual 2022 tax payments were analyzed and weighted against the average service lag. For the 2022 tax year, there was a $0.9 million tax payment made in February 2023, a $8.7 million tax payment made in March 2023 and a $10.0 million tax refund in June 2023 related to the 2022 fiscal year. The overall net refund decreased the 2022 income tax expense lag.

HST Adjustment

HST is collected from customers on certain billed revenues and paid to suppliers on certain expenses and capitalized costs. The difference between HST collections and HST payments in each month is settled with government on the last day of the month that follows the month in which the HST was billed or, if that day is not a business day, on the first business day thereafter.

On average, HST on most of Newfoundland Power's billings is collected from customers before it is settled with government. The Company has use of these funds between the collection date and the settlement date. This reduces the necessary CWC Allowance.

On average, HST billed by Newfoundland Power's suppliers is paid to those suppliers before it is settled with government. The Company has to finance the HST between the payment date and the settlement date. This increases the necessary CWC Allowance.

The net HST impact is a decrease in the Company's proposed 2025 and 2026 test year CWC Allowance of $1,579,000 in 2025 and $1,972,000 in 2026.[9] Newfoundland Power's 2025 and 2026 HST adjustments are set out in Schedule 3 of Appendices A and B.

2.3 Test Year CWC Allowance: 2025 and 2026

Newfoundland Power's proposed 2025 and 2026 test year CWC Allowance based on the calculated revenue lag, expense lag and HST adjustment is $1,475,000 in 2025 and $1,711,000 in 2026.[10] These are set out in Schedule 4 of Appendices A and B.

The effect of the proposed 2025 and 2026 CWC Allowance is to provide Newfoundland Power with a reasonable opportunity to recover its cost of providing regulated service.

[9] By comparison, the 2022 test year HST adjustment of $44,000 and 2023 HST adjustment of $15,000 increased the 2022 and 2023 CWC Allowance.

[10] By comparison, the CWC Allowance included in the 2022 test year was $6,548,000 and $6,800,000 in the 2023 test year.

3.0 Materials and Supplies Allowance

The inclusion of a Materials Allowance in rate base is an accepted practice for regulated utilities. The Materials Allowance provides regulated utilities with a means to reasonably recover the cost of financing inventories. In determining the amounts of materials and supplies to include in rate base, Newfoundland Power is required to exclude that portion that it identifies as expansion inventory.[11]

The Board approved the calculation of Newfoundland Power's rate base including a Materials Allowance based upon: (i) a 13-month average versus a simple average; and (ii) expansion inventory of 19.08% as part of the Company's *2022/2023 General Rate Application*.

For the *2025/2026 General Rate Application*, Newfoundland Power has revised its expansion factor used in the calculation of the Materials Allowance based on a review of actual inventories in 2022 used for expansion projects. The revised expansion factor for the 2025 and 2026 test year is 13.27%, as compared to 19.08% calculated for the 2022 and 2023 test years.

[11] In Order No. P.U. 1 (1974), Newfoundland Power was directed by the Board to identify and exclude all inventories and supplies related to expansion of the electrical system from rate base. The Board noted that materials and supplies related to future expansion were similar in nature to work in progress in that they are held to provide future service. Similar to the treatment of work in progress, materials and supplies related to expansion are excluded in the calculation of rate base.

Newfoundland Power Inc.

2025 Forecast Revenue Lag

	Cash Inflows	2025 Forecast[1] ($000s)	Percent of Total	Net Lag Days	Weighted Average Lag Days
1	Consumer Billings	860,083	98.75%	31.26	30.87
2	Other Billings	10,930	1.25%	48.53	0.61
3	Total	871,013	100.00%		**31.48**

[1] Reconciliation to 2025 Revenue Requirement ($000s):

Total Billings Above	871,013
Rate Stabilization Adjustments	(71,002)
Municipal Tax Billings	(20,666)
Billings Recorded as Revenue	779,345
Revenue Excluded from CWC Allowance	
Revenue Accrual (non-cash)	2,078
Equity Portion of AFUDC	607
Total Revenue	782,030
Deduct: Other Revenue	(13,260)
2025 Revenue Requirement from Rates	768,770

Newfoundland Power Inc.

2025 Forecast Expense Lag

		2025 Forecast	Adjustments[1]	Cash Operating Expenses	Percent of Total	(Lead) Lag Days	Weighted Average (Lead) Lag Days
			($000s)				
	Operating Expenses						
1	Labour	44,875		44,875	6.85%	25.71	1.76
2	Vehicle Expenses	2,177		2,177	0.33%	45.21	0.15
3	Operating Materials	1,311		1,311	0.20%	45.21	0.09
4	Inter-Company Charges	1,895		1,895	0.29%	45.21	0.13
5	Plants, Subs, System Ops & Buildings	3,885		3,885	0.59%	45.21	0.27
6	Travel	1,227		1,227	0.19%	45.21	0.09
7	Tools and Clothing Allowance	1,434		1,434	0.22%	45.21	0.10
8	Conservation	1,867		1,867	0.28%	45.21	0.13
9	Miscellaneous	2,329		2,329	0.36%	45.21	0.16
10	Bank Service Charges & PUB Assessment	1,451		1,451	0.22%	(17.32)	(0.04)
11	Uncollectible Bills	2,222	2,222	-	0.00%		-
12	Insurance	2,773		2,773	0.42%	(167.50)	(0.70)
13	Pension Expense	1,098	59	1,039	0.16%	21.62	0.03
14	Other Post Employment Benefits	7,024	2,653	4,371	0.67%	24.66	0.17
15	Severance and Other Employee Costs	163		163	0.02%	45.21	0.01
16	Education and Training	543		543	0.08%	45.21	0.04
17	Trustee & Directors' Fees	772		772	0.12%	30.81	0.04
18	Other Company Fees	6,473		6,473	0.99%	45.21	0.45
19	Stationery & Copying	251		251	0.04%	45.21	0.02
20	Equipment Rental & Maintenance	702		702	0.11%	45.21	0.05
21	Telecommunications	1,775		1,775	0.27%	45.21	0.12
22	Postage	1,207		1,207	0.18%	45.21	0.08
23	Advertising	1,513		1,513	0.23%	45.21	0.10
24	Vegetation Management	3,377		3,377	0.52%	45.21	0.24
25	Computer Equipment & Software	4,702		4,702	0.72%	45.21	0.32
26	Gross Operating Expenses	97,046		92,112			
27	Less: GEC	(3,034)		(3,034)	-0.46%	35.31	(0.16)
28	Net Operating Expenses	94,012		89,078			
29	Less: Non-Regulated Expenses	(3,544)		(3,544)	-0.54%	34.30	(0.19)
30	**Regulated Operating Expenses**	90,468		85,534			
31							
32	**Purchased Power**	530,628		530,628	80.97%	35.65	28.87
33							
34	**Current Income Tax**						
35	Total Tax	26,404	8,978	17,426			
36	Plus: Tax Effects of Non-Regulated Expenses	1,063		1,063			
37	Regulated Current Income Tax	27,467		18,489	2.82%	9.93	0.28
38							
39	**Municipal Tax Paid**			20,666	3.15%	(89.75)	(2.83)
40							
41	**Cash Operating Expenses in CWC Allowance**			655,317	100.00%		**29.78**
42							
43	**Costs Excluded from CWC Allowance**						
44	Return on Rate Base	104,049					
45	Depreciation Expense	83,143					
46	Deferred cost recoveries and amortizations[2]	(12,014)					
47		175,178					
48							
49	**2025 Revenue Requirement**	823,741					

[1] Represents items that are not reoccurring cash operating expenses.

[2] Includes deferred cost recoveries and amortizations (-\$11,571,000), the deferred recovery of conservation costs (-\$5,774,000), the deferred recovery of electrification costs (-\$523,000), the amortization of conservation costs (\$5,345,000), the amortization of hearing costs (\$200,000) and the amortization of electrification costs (\$309,000). See *Volume 1, Application, Company Evidence and Exhibits, Section 3.5: Regulatory Amortizations* for a summary of the Company's 2025 deferred cost recoveries and amortizations.

Newfoundland Power Inc.

2025 Forecast HST Adjustment

		HST ($000s)	Net (Lead) Lag Days	CWC Allowance[1] ($000's)
1	Consumer Billings	(128,444)	(29.57)	(10,406)
2	Other Billings	(1,688)	2.90	13
3	Purchased Power	79,594	40.39	8,808
4	Operating Expenses	5,151	0.41	6
5				**(1,579)**

[1] (Lead) Lag Days / 365 * HST.

Newfoundland Power Inc.

2025 Forecast Cash Working Capital Allowance

CWC Factor	
Revenue Lag Days (Schedule 1)	31.48
Expense Lag Days (Schedule 2)	(29.78)
Net Lag Days	1.70
CWC Factor (1.70 days divided by 365 days)	0.466%
CWC Allowance	
Total Cash Operating Expenses (Schedule 2)	655,317
CWC Factor	0.466%
	3,054
HST Adjustment (Schedule 3)	(1,579)
CWC Allowance	**1,475**

Newfoundland Power Inc.

2026 Forecast Revenue Lag

	Cash Inflows	2026 Forecast[1] ($000s)	Percent of Total	Net Lag Days	Weighted Average Lag Days
1	Consumer Billings	883,469	99.04%	31.26	30.96
2	Other Billings	8,546	0.96%	48.53	0.47
3	Total	892,015	100.00%		**31.43**

[1] Reconciliation to 2026 Revenue Requirement ($000s):

Total Billings Above	892,015
Rate Stabilization Adjustments	(70,525)
Municipal Tax Billings	(21,191)
Billings Recorded as Revenue	800,299
Revenue Excluded from CWC Allowance	
Revenue Accrual (non-cash)	(365)
Equity Portion of AFUDC	763
Total Revenue	800,697
Deduct: Other Revenue	(11,095)
2026 Revenue Requirement from Rates	789,602

Newfoundland Power Inc.

2026 Forecast Expense Lag

		2026 Forecast	Adjustments[1]	Cash Operating Expenses	Percent of Total	(Lead) Lag Days	Weighted Average (Lead) Lag Days
			($000s)				
	Operating Expenses						
1	Labour	46,799		46,799	7.14%	25.71	1.84
2	Vehicle Expenses	2,212		2,212	0.34%	45.21	0.15
3	Operating Materials	1,332		1,332	0.20%	45.21	0.09
4	Inter-Company Charges	1,969		1,969	0.30%	45.21	0.14
5	Plants, Subs, System Ops & Buildings	3,948		3,948	0.60%	45.21	0.27
6	Travel	1,247		1,247	0.19%	45.21	0.09
7	Tools and Clothing Allowance	1,458		1,458	0.22%	45.21	0.10
8	Conservation	1,897		1,897	0.29%	45.21	0.13
9	Miscellaneous	2,369		2,369	0.36%	45.21	0.16
10	Bank Service Charges & PUB Assessment	1,475		1,475	0.23%	(17.32)	(0.04)
11	Uncollectible Bills	2,258	2,258	-	0.00%		-
12	Insurance	2,932		2,932	0.45%	(167.50)	(0.75)
13	Pension Expense	(1,824)	(2,799)	975	0.15%	21.62	0.03
14	Other Post Employment Benefits	3,637	(943)	4,580	0.70%	24.66	0.17
15	Severance and Other Employee Costs	166		166	0.03%	45.21	0.01
16	Education and Training	551		551	0.08%	45.21	0.04
17	Trustee & Directors' Fees	785		785	0.12%	30.81	0.04
18	Other Company Fees	6,401		6,401	0.98%	45.21	0.44
19	Stationery & Copying	255		255	0.04%	45.21	0.02
20	Equipment Rental & Maintenance	713		713	0.11%	45.21	0.05
21	Telecommunications	1,791		1,791	0.27%	45.21	0.12
22	Postage	1,203		1,203	0.18%	45.21	0.08
23	Advertising	1,538		1,538	0.24%	45.21	0.11
24	Vegetation Management	3,432		3,432	0.52%	45.21	0.24
25	Computer Equipment & Software	4,992		4,992	0.76%	45.21	0.34
26	Gross Operating Expenses	93,536		95,020			
27	Less: GEC	(3,106)		(3,106)	-0.47%	35.31	(0.17)
28	Net Operating Expenses	90,430		91,914			
29	Less: Non-Regulated Expenses	(3,691)		(3,691)	-0.56%	34.30	(0.19)
30	**Regulated Operating Expenses**	86,739		88,223			
31							
32	**Purchased Power**	522,388		522,388	79.70%	35.65	28.41
33							
34	**Current Income Tax**						
35	Total Tax	26,433	3,935	22,498			
36	Plus: Tax Effects of Non-Regulated Expenses	1,107		1,107			
37	Regulated Current Income Tax	27,540		23,605	3.60%	9.93	0.36
38							
39	**Municipal Tax Paid**			21,191	3.23%	(89.75)	(2.90)
40							
41	**Cash Operating Expenses in CWC Allowance**			655,407	100.00%		**29.38**
42							
43	**Costs Excluded from CWC Allowance**						
44	Return on Rate Base	104,668					
45	Depreciation Expense	86,691					
46	Deferred cost recoveries and amortizations[2]	9,901					
47		201,260					
48							
49	**2026 Revenue Requirement**	837,927					

[1] Represents items that are not reoccurring cash operating expenses.

[2] Includes deferred cost recoveries and amortizations ($9,888,000), the deferred recovery of conservation costs (-$5,895,000), the deferred recovery of electrification costs (-$534,000), the amortization of conservation costs ($5,659,000), the amortization of hearing costs ($400,000) and the amortization of electrification costs ($383,000).

See *Volume 1, Application, Company Evidence and Exhibits, Section 3.5: Regulatory Amortizations* for a summary of the Company's 2026 deferred cost recoveries and amortizations.

Newfoundland Power Inc.

2026 Forecast HST Adjustment

		HST ($000s)	Net (Lead) Lag Days	CWC Allowance[1] ($000's)
1	Consumer Billings	(131,580)	(29.57)	(10,660)
2	Other Billings	(1,330)	2.90	11
3	Purchased Power	78,358	40.39	8,671
4	Operating Expenses	5,234	0.41	6
5				**(1,972)**

[1] (Lead) Lag Days / 365 * HST.

Newfoundland Power Inc.

2026 Forecast Cash Working Capital Allowance

	CWC Factor	
1	Revenue Lag Days (Schedule 1)	31.43
2	Expense Lag Days (Schedule 2)	(29.38)
3	Net Lag Days	2.05
4		
5	CWC Factor (2.05 days divided by 365 days)	0.562%
6		
7		
8		
9		
10	**CWC Allowance**	
11		
12	Total Cash Operating Expenses (Schedule 2)	655,407
13	CWC Factor	0.562%
14		3,683
15	HST Adjustment (Schedule 3)	(1,972)
16	**CWC Allowance**	**1,711**

Customer, Energy and Demand Forecast

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1.0 Introduction

The Customer, Energy and Demand Forecast is prepared annually and forms the foundation of Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") planning process. The forecast is a key input in developing estimates of capital expenditures required to ensure the electrical system meets the demands associated with both customer growth and energy sales. The forecast also directly addresses the estimation of future revenue from electricity sales and the Company's single largest expenditure, purchased power.

The forecast was created as of September 2023.

2.0 Forecast Methodology

Newfoundland Power provides electrical service to three categories of customers: Domestic, General Service and Street and Area Lighting. In 2022, Domestic customers accounted for 61.3% of total energy sales, while General Service and Street and Area Lighting customers accounted for 38.2% and 0.5%, respectively.

2.1 Domestic

The Domestic category includes Rate #1.1 Domestic Service and Rate #1.1S Domestic Seasonal – Optional. The Domestic category primarily refers to residential dwellings, including single detached homes, single attached homes, apartments and mobile homes. This category also includes non-residential services, such as cottages, personal use garages and other metered services that qualify for the Domestic rate category. Residential customers use electricity primarily for space and water heating, the operation of miscellaneous appliances, and lighting.

In this category, a customer/average use methodology is employed, where growth in the number of customers is primarily based on forecast housing completions. Average use is forecast using an end-use/econometric model that includes the market share for electric space heating, household disposable income and the marginal price of electricity in the current and previous year. The model also includes variables to reflect the impacts on energy sales of electrification, oil-to-electric conversions and Conservation and Demand Management ("CDM") programs, as well as the market penetration of heat pumps.

2.2 General Service

The General Service category primarily refers to commercial, institutional and industrial customers. While the Domestic category represents a relatively homogenous group of customers, the General Service category represents a diverse group whose activities include trade, finance, real estate, public administration, health, education, commercial services, transportation, manufacturing, mining, fishing, forestry and construction. These customers provide goods and services to the local market as well as for export. In 2022, approximately 85% of energy sales in this category were to customers in the service producing sector of the economy and 15% were in the goods producing sector.

For forecasting purposes, the General Service category is divided into small General Service, which includes Rate #2.1 General Service 0 – 100 kW (110 kVA), and large General Service, which includes Rate #2.3 General Service 110 kVA (100 kW) – 1000 kVA and Rate #2.4 General Service 1000 kVA and Over.

In the small General Service category, the growth in the number of customers is primarily based on forecast Domestic customer growth. Energy sales are forecast using an econometric model that includes the Gross Domestic Product ("GDP") for the service sector, the average price of electricity in the current year, and the number of customers. The model also includes a variable to reflect the impact of CDM programs and electrification on energy sales.

Given the relatively small number of customers in the large General Service category, an informed opinion methodology is employed and energy sales are forecast on an individual customer basis.

2.3 Street and Area Lighting

Street and Area Lighting energy sales primarily relate to the number of fixtures required to meet the lighting needs of municipalities and unincorporated communities. At the end of 2022, approximately 66,000 fixtures were installed.

Given the nature of this category, an end-use forecasting methodology is employed. The Street and Area Lighting sales forecast is determined by multiplying the forecast quantity of high-pressure sodium ("HPS") and light-emitting diode ("LED") fixtures by the amount of electricity consumed for each fixture type and wattage. The Street and Area Lighting sales forecast includes the effects of Newfoundland Power's *LED Street Lighting Replacement Plan* to replace all HPS fixtures with LED fixtures over a six-year period.[1]

2.4 Produced and Purchased

Total energy sales are calculated by adding Domestic, General Service, and Street and Area Lighting sales. Company use, system losses and wheeled energy are then added to total energy sales to obtain total produced, purchased and wheeled. Company use includes all electricity consumed in facilities owned by Newfoundland Power and used in the delivery of service to customers. System losses refer to energy that is lost during the transmission and distribution of energy between the source of supply and delivery to customers. Wheeled information is provided by Newfoundland and Labrador Hydro ("Hydro").[2]

Purchased energy is calculated by subtracting normal hydro production ("normal production") from the forecast of total produced and purchased. Each year, normal production is adjusted to reflect plant availability and any modifications to plants that may impact production.

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[1] Newfoundland Power's *LED Street Lighting Replacement Plan* was filed with the Board as part of the Company's *2021 Capital Budget Application*. The plan includes replacement of approximately 60,000 HPS fixtures with LED fixtures over a 6-year period from 2021 to 2026. Annual approval of capital expenditures associated with the plan were approved by the Board in Order Nos. P.U. 37 (2020), P.U. 36 (2021), and P.U. 38 (2022).

[2] Wheeled energy represents energy that is supplied to Hydro's customers through Newfoundland Power's electrical system.

2.5 Peak Demand

Newfoundland Power forecasts its native peak demand ("peak demand") to estimate its expected purchased power costs from Hydro throughout the forecast period.[3] Newfoundland Power's native peak is determined using a load factor-based methodology.[4] The load factor used in the calculation is the average of five years of normalized annual load factors.[5] Native peak is calculated by applying the average load factor to total produced and purchased power. Purchased power demand is calculated by subtracting the Generation Credit and Curtailable Credit from native peak.[6]

3.0 Key Forecast Assumptions

The forecasting process relies on a wide range of information related to the economy, energy prices, electrification and CDM activities, and other resource-based developments within Newfoundland Power's service territory.

3.1 Economic Outlook

The economic assumptions used in preparing the forecast are based on The Conference Board of Canada's *Provincial Medium-Term Economic Forecast,* dated August 2023. A table summarizing the key economic indicators used in preparing the forecast is provided in Appendix A.

The provincial economy encountered challenges in 2022, with Real GDP contracting by 1.4%. This was largely due to a slowdown in the oil and gas sector combined with slowdowns in the mining, and manufacturing sectors. Further reductions in these sectors are forecast for 2023, but are expected to be less severe. Scheduled maintenance at the Hebron and White Rose oil platforms and delays in bringing the Terra Nova platform back online will hurt oil and gas output in 2023. The sector is expected to rebound in 2024 as production increases.[7]

Construction is expected to be a major driver of economic activity for the province this year.

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3 Hydro's Billing Demand is determined by subtracting the load curtailment and generation credits from native peak.

4 Load factor is the ratio of the average demand on the electrical system to the peak demand on the system. Newfoundland Power's typical load factor is approximately 50%. Conceptually, this implies that the peak demand Newfoundland Power will expect in a year will be approximately twice the average demand for the year. Hydro's demand and energy wholesale rate was first approved by the Board in Order No. P.U. 44 (2004).

5 The five-year average system load factor used by Newfoundland Power includes actual system load factors from 2018 to 2022. The Company's load factor in 2020 was the highest recorded system load factor in at least 30 years and was influenced by public health measures in effect to manage the COVID-19 pandemic. The 2020 load factor was therefore excluded in forecasting Newfoundland Power's peak demand.

6 Newfoundland Power's Utility rate from Hydro includes a Generation Credit to account for Newfoundland Power's generating capacity less allowance for system reserve. The Generation Credit was most recently approved in Order No. P.U. 30 (2019). Hydro's Utility rate for Newfoundland Power also includes a Curtailable Credit to account for load that can be curtailed by Newfoundland Power's Curtailable Service Option customers. In order to receive the Curtailable Credit, Newfoundland Power must demonstrate the capability to curtail its customer load requirements to the level of the Curtailable Credit.

7 The Conference Board of Canada, *Economy Recovery Delayed as Growth Stalls: Newfoundland and Labrador's* Three-Year Outlook ("*Newfoundland and Labrador's Three-Year Outlook*"), September 6, 2023, page 6.

Several ongoing construction projects such as the West White Rose project have kept construction activity healthy in 2023. In addition to ongoing construction projects related to oil and gas, mining, and health care, there was significant investment in transportation infrastructure including the expansions of the Trans-Canada Highway and the Port of Argentia. This will partially offset the reduced oil production resulting in a 0.2% decrease in provincial Real GDP in 2023. As the resource-based industries perform better, the province's economic growth is expected to strengthen to 1.6% in 2024 followed by 1.4% in 2025.[8] In 2026, provincial Real GDP is expected to increase by 1.1%.[9]

The population of Newfoundland and Labrador is forecast to increase by 1.6% in 2023, the highest growth rate since the early 1970s. These population gains are expected to slow in 2024 and resume a long-term decline in 2025 and beyond.[10] The Conference Board of Canada expects the increase in annual immigration spaces recently announced by the provincial government may offset some of the province's demographic challenges.[11]

The economic recovery from the COVID-19 pandemic and population gains in recent years have supported employment and labour force growth in Newfoundland and Labrador since 2021. While the province's labour force grew by 2.1% in 2022, it is expected to mirror the population trend, dropping to 0.3% growth in 2023 before averaging annual losses of 0.1% in future years.[12] Anticipated employment trends reflect the demographic challenges of a declining and aging population. One sector that is expected to benefit from the needs of an aging population is the health and social services industry which is forecast to gain 1,440 jobs in 2023. Employment gains in this industry account for approximately 45% of the total employment gains for the province in 2023.[13]

The impact of high inflation and interest rates have weakened consumer purchasing power in 2023. Despite easing inflationary pressures, weakening population and employment growth over the medium term is expected to cause real household spending to contract by 0.5% and 0.1% in 2023 and 2024, respectively, before growing by 0.8% in 2025.[14] Housing starts are also expected to decline over the forecast period due to higher mortgage rates and demographic trends.[15] Housing starts were 1,379 in 2022 and are expected to decline to 821 in 2023, 707 in 2024, 616 in 2025, and 525 in 2026.[16]

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8 Ibid, page 6.
9 See Attachment 1, Page 2 of 2.
10 The Conference Board of Canada, *Economy Recovery Delayed as Growth Stalls: Newfoundland and Labrador's* Three-Year Outlook ("*Newfoundland and Labrador's Three-Year Outlook*"), September 6, 2023, page 6.
11 Ibid. See also Government of Newfoundland and Labrador News Release: *Ministerial Statement – Doubling Immigration Spaces for 2023 to Welcome More Newcomers Throughout Newfoundland and Labrador*, April 26, 2023.
12 The Conference Board of Canada, *Economy Recovery Delayed as Growth Stalls: Newfoundland and Labrador's* Three-Year Outlook ("*Newfoundland and Labrador's Three-Year Outlook*"), September 6, 2023, page 7.
13 Ibid.
14 Ibid, page 8.
15 Ibid, page 11.
16 See Attachment 1, Page 2 of 2.

3.2 Energy Prices Outlook

Changes in energy prices have a direct impact on energy sales through the inclusion of price elasticity effects in the various models. Overall, customer response to changes in the price of electricity in the short-term is relatively inelastic. Current analysis indicates that a 1% increase in the price of electricity will result in a 0.19% decrease in energy sales. The analysis indicates the response will vary depending on the timeframe and rate category. In addition, changes in oil prices can impact the market share of electricity in the space heating market.

Electricity price forecasts are developed based on information available internally and information provided by Hydro. The energy sales forecast under existing rates includes: (i) a 6.9% increase on July 1, 2023 related to the annual July 1st rate adjustment; (ii) an approximate 9% increase on July 1, 2024 reflecting anticipated rate pressures associated with the July 1st rate adjustment of 7.5% as well as the 1.5% rate increase associated with Newfoundland Power's *2024 Rate of Return on Rate Base Application* filed with the Board on November 23, 2023;[17] and (iii) a 2.25% increase on July 1st in each of 2025 and 2026.[18] The Company's proposed 5.5% increase in customer rates effective July 1, 2025 has also been included in the energy sales forecast under proposed rates.

Furnace oil prices increased by approximately 68% in 2022, which was largely due to the effect of geopolitical events on the world economy and oil markets. In 2023, a decrease of 8% is expected, which reflects the announcement that furnace oil carbon tax has been paused for three years.[19] From 2024 to 2026, the price is expected to be stable until the carbon tax is reintroduced in 2027. However, there is considerable uncertainty due to volatility in world oil prices.[20]

3.3 CDM and Electrification Impacts

The energy sales component of the forecast includes the impact of CDM programs as well as government electrification initiatives such as its oil to electric program as well as forecast electric vehicle adoption.

3.4 Net Metering Service Option

The Net Metering Service Option was introduced in 2017 and permits customers to install generation on their premises to offset part or all of their electrical requirements. As of December 31, 2022, Newfoundland Power's customers have installed 29 net metering projects. This includes: (i) 27 solar projects ranging in capacity from 2.0 kW to 44.2 kW; and (ii) two wind projects with capacities of 5 kW and 10.0 kW. The total installed capacity of the Company's Net Metering Service option is 303.3 kW.[21]

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17 For the purposes of estimating the impact of the July 1st rate adjustment, Hydro's indicated increase of 7.5% was used. See footnote 3 in Hydro's response to Request for Information PUB-NLH-236 filed as part of the *Reliability and Resource Adequacy Study Review*.

18 Annual rate increases of 2.25% are based on the Provincial Government's April 2019 release *Protecting You from the Cost Impacts of Muskrat Falls.*

19 On October 26, 2023 the federal government announced a three-year pause on furnace oil carbon tax.

20 Based on the US Energy Information Administration's *Short-Term Energy Outlook*, September 2023.

21 See Newfoundland Power's *2022 Net Metering Service Option Annual Report* filed with the Board on March 24, 2023.

Given the low installed capacity of the Net Metering Service Option to date, no adjustments have been made to the forecast on this basis.

3.5 Other Inputs

Information from a number of other sources is used in preparing the forecast. Newfoundland Power surveyed approximately 105 large General Service customers representing approximately 175 customer accounts in 2023 to request information on future load requirements. This information, along with information gathered from the Company's regional operations, the Atlantic Economic Council, and the provincial and federal governments, is also incorporated into the large General Service forecast.

4.0 Customer and Energy Forecast

Newfoundland Power's energy sales declined each year from 2016 to 2021.[22] This was in contrast to the annual growth in energy sales experienced by the Company in the prior decade.[23] In 2022, energy sales increased due to increased domestic average usage. This resulted from the increased price of furnace oil and the province's population growth, both of which were influenced by geopolitical events that resulted in higher immigration to the province. Additionally, there were increased General Service energy sales in 2022 compared to 2021 as COVID-19 public health measures were lifted.

Newfoundland Power is forecasting that energy sales in 2023 will also increase. During the forecast period, energy sales are expected to be influenced primarily by conversions from oil to electric heating, major projects, energy prices, CDM programs and the continued adoption of heat pumps to offset electric baseboard heating. Changes in key economic indicators, such as service sector GDP, household disposable income, and housing starts and completions will also impact forecast energy sales.

Appendix B provides actual customer and energy sales for 2021 and 2022, and forecast customer and energy sales for 2023 through 2026 under both existing and proposed rates.

With a weak economic outlook, customer growth is expected to remain low over the forecast period. The total number of customers is forecast to increase by 0.6% in 2023, 0.4% in each of 2024 and 2025, and 0.3% in 2026. Energy sales under existing rates are forecast to increase by 2.8%, 0.5% and 0.9% in 2023, 2024 and 2025, respectively, followed by a decrease of 0.1% in 2026.[24] Energy sales under proposed rates, which include the elasticity effects of the proposed 5.5% customer rate increase, are forecast to increase by 0.5% in 2024 and 0.6% in 2025, followed by a decrease of 0.7% in 2026.

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[22] Newfoundland Power's annual energy sales declined by an average of approximately 0.7% over the 2016 to 2021 period.

[23] Between 2004 and 2015, Newfoundland Power experienced annual sales growth of approximately 1.7%.

[24] Forecast energy sales in 2024 positively impacted by approximately 0.3% due to 2024 being a leap year.

Domestic

Growth in the number of Domestic customers is largely a result of housing starts and completions. Based on The Conference Board of Canada forecasts of housing starts and completions, the number of Domestic customers is forecast to grow by 0.5%, 0.4%, 0.4% and 0.3% in 2023, 2024, 2025 and 2026, respectively.

Domestic electricity consumption is a function of the major end uses in the home, such as space heating, water heating, lighting, and major appliances. Changes in customer heating sources in recent years, particularly as it relates to oil to electric conversions and adoption of heat pumps to offset baseboard heating influences domestic electricity consumption. Changes in energy prices, household disposable income, and CDM programs also have an impact on electricity consumption. Under proposed rates, the average use of energy is forecast to increase by 2.8% in 2023 and decrease by 0.4%, 1.8% and 1.3% in 2024, 2025 and 2026 respectively.

The combined impact of the increased number of customers and changes in average use is forecast to increase Domestic energy sales under proposed rates of 3.4% in 2023. Domestic energy sales are expected to be flat in 2024 and decrease by 1.1% and 0.1% in 2025 and 2026, respectively.

General Service

In the small General Service Rate #2.1 rate class, customers and energy sales growth are dependent on growth in the service producing sector of the GDP, changes in the price of electricity and the impact of electrification and CDM programs. In the large General Service Rate #2.3 and Rate #2.4 rate classes, energy sales are primarily determined by changes in the load of larger customers in the goods producing sector. Information obtained from specific customers is incorporated into forecasts for General Service Rate #2.3 and Rate #2.4 customers.

Overall, the number of General Service customers is forecast to grow by 0.8% in 2023, and 0.4% in each of 2024, 2025 and 2026. Under proposed rates, General Service energy sales are forecast to increase by 2.2%, 1.6% and 4.0% in 2023, 2024 and 2025 respectively, followed by a 0.1% decrease in 2026. The energy sales growth in 2024 and 2025 is primarily related to Memorial University's conversion of its oil boilers to electric.[25]

Street and Area Lighting

The number of Street and Area Lighting customers is forecast to increase by 0.7%, 0.6%, 0.5% and 0.5% in 2023, 2024, 2025 and 2026, respectively. Energy sales are forecast to decrease by 9.3%, 10.6%, 11.0% and 11.4% in 2023, 2024, 2025 and 2026, respectively. The decrease in energy sales is due to the Company's six-year *LED Street Lighting Replacement Plan,* which will replace all

[25] The forecast load at Memorial University is expected to reach over 40 MVA following the university's addition of electric boilers to its oil-fired boiler system. The project is being executed with funding from the provincial and federal governments to help meet net-zero objectives. See Provincial Government press release, *Provincial and Federal Governments Invest in Electrification Project at Memorial University*, March 25, 2022.

HPS street light fixtures with more energy-efficient LED street light fixtures from 2021 to 2026.[26]

Produced and Purchased

Produced and purchased is the sum of total energy sales, company use and system losses. The forecast of company use is based on historical energy usage and information gathered from each of Newfoundland Power's operating areas with respect to the operation of these facilities. System losses are forecast to be approximately 4.8% of total produced and purchased throughout the forecast period.[27]

5.0 Purchased Energy and Demand Forecast

Purchased energy is calculated by subtracting Newfoundland Power's normal production from produced and purchased. The Company's normal production for 2023 is 425.6 GWh.[28] Normal production is projected to be 424.4 GWh in 2024 and 429.0 GWh for 2025 and 2026.[29]

Newfoundland Power's forecast of native peak demand is determined by applying the average weather-adjusted load factor to the forecast of produced and purchased energy. The Company's purchased demand is then derived by subtracting load curtailment by Newfoundland Power customers and company-owned facilities, and the generation credit approved by the Board.

The Purchased Energy and Demand Forecast is provided in Appendix C.

6.0 Forecast Accuracy

The energy sales forecasts and actual weather-adjusted energy sales for the past 10 years are provided in Appendix D. During this period, differences from forecast have ranged from a high of 1.5% to a low of -1.1%. In six of the past 10 years, differences from forecast were 1% or less. The average forecast accuracy over the 10 year period was -0.25%.

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26 See Newfoundland Power's *2021 Capital Budget Application*. The first year of the plan was approved by the Board in Order No. P.U. 37 (2020). Approval of annual capital expenditures in subsequent years were approved by the Board in Order Nos. P.U. 36 (2021), and P.U. 38 (2022).

27 System losses were 4.8% of total produced and purchased in 2022.

28 On February 3, 2023, Newfoundland Power filed its annual letter to the Board detailing its normal production for 2023, including adjustments made to reflect scheduled outages in 2023.

29 Normal production of 424.4 GWh in 2024 reflects scheduled outages in 2024. For 2025 and 2026, normal production of 429.0 GWh includes a three-year average reduction for typical scheduled outage levels.

Newfoundland Power Inc.

Key Economic Indicators[1]
2012 - 2026F

(millions of dollars)

	Actual				Forecast					
Indicator	**Average 2012 -2021**	**2022**	**2023**	**Change From 2022**	**2024**	**Change From 2023**	**2025**	**Change From 2024**	**2026**	**Change From 2025**
Gross Domestic Product (Millions 2012 $)										
Goods Producing Industries	-0.2%	13,525	13,373	-1.1%	13,875	3.8%	14,120	1.8%	14,310	1.3%
Service Producing Industries	0.6%	16,530	16,637	0.6%	16,588	-0.3%	16,782	1.2%	16,953	1.0%
Total of All Industries	0.3%	30,150	30,106	-0.1%	30,559	1.5%	30,997	1.4%	31,358	1.2%
Labour Force ('000s)	-0.8%	262	263	0.3%	262	-0.1%	263	0.2%	262	-0.3%
Employment ('000s)	-0.8%	232	236	1.4%	233	-1.0%	234	0.2%	234	-0.1%
Consumer Price Index (2002=1.000)	1.7%	1.539	1.587	3.1%	1.623	2.3%	1.654	1.9%	1.687	2.0%
Household Disposable Income (Millions $)	2.6%	18,560	19,349	4.3%	19,797	2.3%	20,105	1.6%	20,305	1.0%
Unemployment Rate (%)	N/A[2]	11.2%	10.3%	N/A	11.0%	N/A	11.1%	N/A	10.9%	N/A
Retail Sales (Millions $)	2.6%	11,221	11,563	3.0%	11,720	1.4%	11,861	1.2%	11,975	1.0%
Housing Starts - Units	N/A[3]	1,379	821	-40.5%	707	-13.9%	616	-12.9%	525	-14.8%
Housing Completions - Units	N/A[3]	1,130	889	-21.3%	702	-21.0%	616	-12.3%	527	-14.4%
Canadian GDP Deflator (2012=1.000)	2.0%	1.279	1.291	0.9%	1.316	1.9%	1.337	1.6%	1.359	1.6%

[1] The Conference Board of Canada, *Provincial Medium-Term Economic Forecast* , August 2023.
[2] The unemployment rate increased from 12.8% in 2012 to 13.1% in 2021.
[3] The average number of housing starts and completions over the 2012 to 2021 period were 1,719 units and 1,838 units, respectively.

Newfoundland Power Inc.

Customer and Energy Forecast
2022 - 2026F

		Actual	Forecast		Forecast		Existing				Proposed			
		2022	2023	Change From 2022	2024	Change From 2023	2025	Change From 2024	2026	Change From 2025	2025	Change From 2024	2026	Change From 2025
Customers														
Domestic														
Regular	1.1	237,054	238,306	0.5%	239,296	0.4%	240,162	0.4%	240,907	0.3%	240,162	0.4%	240,907	0.3%
Seasonal	1.1	1,299	1,299	0.0%	1,299	0.0%	1,299	0.0%	1,299	0.0%	1,299	0.0%	1,299	0.0%
Total Domestic		238,353	239,605	0.5%	240,595	0.4%	241,461	0.4%	242,206	0.3%	241,461	0.4%	242,206	0.3%
General Service														
0-100 kW (110 kVA)	2.1	23,069	23,243	0.8%	23,352	0.5%	23,453	0.4%	23,547	0.4%	23,453	0.4%	23,547	0.4%
110 kVA (100 kW) - 1000 kVA	2.3	1,258	1,273	1.2%	1,273	0.0%	1,273	0.0%	1,273	0.0%	1,273	0.0%	1,273	0.0%
1000 kVA and Over	2.4	59	60	1.7%	59	-1.7%	59	0.0%	57	-3.4%	59	0.0%	57	-3.4%
Total General Service		24,386	24,576	0.8%	24,684	0.4%	24,785	0.4%	24,877	0.4%	24,785	0.4%	24,877	0.4%
Street and Area Lighting	4.1	11,025	11,100	0.7%	11,165	0.6%	11,221	0.5%	11,276	0.5%	11,221	0.5%	11,276	0.5%
Total Customers		273,764	275,281	0.6%	276,444	0.4%	277,467	0.4%	278,359	0.3%	277,467	0.4%	278,359	0.3%
Energy Sales (GWh)														
Domestic														
Regular	1.1	3,536.3	3,655.7	3.4%	3,655.4	0.0%	3,616.6	-1.1%	3,613.6	-0.1%	3,603.1	-1.4%	3,568.5	-1.0%
Seasonal	1.1	11.7	11.3	-3.4%	11.5	1.8%	11.5	0.0%	11.5	0.0%	11.5	0.0%	11.5	0.0%
Total Domestic		3,548.0	3,667.0	3.4%	3,666.9	0.0%	3,628.1	-1.1%	3,625.1	-0.1%	3,614.6	-1.4%	3,580.0	-1.0%
General Service														
0-100 kW (110 kVA)	2.1	781.3	790.7	1.2%	795.5	0.6%	795.3	0.0%	798.0	0.3%	792.6	-0.4%	795.1	0.3%
110 kVA (100 kW) - 1000 kVA	2.3	1,034.6	1,064.4	2.9%	1,069.8	0.5%	1,072.0	0.2%	1,070.6	-0.1%	1,072.0	0.2%	1,070.6	-0.1%
1000 kVA and Over	2.4	392.6	401.7	2.3%	426.5	6.2%	518.5	21.6%	514.7	-0.7%	518.5	21.6%	514.7	-0.7%
Total General Service		2,208.5	2,256.8	2.2%	2,291.8	1.6%	2,385.8	4.1%	2,383.3	-0.1%	2,383.1	4.0%	2,380.4	-0.1%
Street and Area Lighting	4.1	28.0	25.4	-9.3%	22.7	-10.6%	20.2	-11.0%	17.9	-11.4%	20.2	-11.0%	17.9	-11.4%
Total Energy Sales		5,784.5	5,949.2	2.8%	5,981.4	0.5%	6,034.1	0.9%	6,026.3	-0.1%	6,017.9	0.6%	5,978.3	-0.7%
Company Use		10.7	10.8	0.9%	10.8	0.0%	10.8	0.0%	10.8	0.0%	10.8	0.0%	10.8	0.0%
Losses		292.1	300.5	2.9%	302.2	0.6%	304.8	0.9%	304.4	-0.1%	304.0	0.6%	302.0	-0.7%
Produced & Purchased		6,087.3	6,260.5	2.8%	6,294.4	0.5%	6,349.7	0.9%	6,341.5	-0.1%	6,332.7	0.6%	6,291.1	-0.7%
Wheeled		120.1	110.1	-8.3%	108.8	-1.2%	106.5	-2.1%	106.3	-0.2%	106.5	-2.1%	106.3	-0.2%
Total System Energy		6,207.4	6,370.6	2.6%	6,403.2	0.5%	6,456.2	0.8%	6,447.8	-0.1%	6,439.2	0.6%	6,397.4	-0.6%

Newfoundland Power Inc.

Purchased Energy and Demand Forecast
2023 - 2026F

Year	Produced Purchased & Wheeled	Total Wheeled Energy	Total Produced & Purchased (NP Native Peak)			Total Curtailed Demand	NP Produced		Total Purchased	
				(1)	(2) Load	(3)	(4)	(5) Credit		(6)
	GWH	GWH	GWH	MW	Factor	MW	GWH	MW	GWH	MW
Existing										
2023	6,370.6	110.1	6,260.5	1,448.164	49.35%	12.0	426.1	118.054	5,834.4	1,318.110
2024	6,403.2	108.8	6,294.4	1,476.259	49.35%	12.0	424.4	118.054	5,870.0	1,346.205
2025	6,456.2	106.5	6,349.7	1,468.798	49.35%	12.0	429.0	118.054	5,920.7	1,338.744
2026	6,447.8	106.3	6,341.5	1,466.901	49.35%	12.0	429.0	118.054	5,912.5	1,336.847
Proposed										
2023	6,370.6	110.1	6,260.5	1,448.164	49.35%	12.0	426.1	118.054	5,834.4	1,318.110
2024	6,403.2	108.8	6,294.4	1,476.259	49.35%	12.0	424.4	118.054	5,870.0	1,346.205
2025	6,439.2	106.5	6,332.7	1,464.865	49.35%	12.0	429.0	118.054	5,903.7	1,334.811
2026	6,397.4	106.3	6,291.1	1,455.242	49.35%	12.0	429.0	118.054	5,862.1	1,325.188

Notes:

1. Native peak is the maximim demand forecast to be served by Newfoundland Power. The 2023 native peak reflects the forecast for the winter period of December 2023 to March 2024. Upward adjustment made for 2024 relating to increased load at Memorial University.
2. Load Factor is based on an average of five year historical (normalized) load factors with 2020 excluded.
3. Based on historical performance of participants plus curtailment of company owned facilities.
4. Normal production for the forecast period is 438.4 GWh adjusted for plant availability and efficiency improvements. Produced for 2023 also includes 0.5 GWh of production at Newfoundland Power's thermal plants.
5. Assumes a generation credit of 118.054 MW.
6. The purchased demand for 2023 reflects the purchased demand from Newfoundland and Labrador Hydro for the winter period of December 2023 to to March 2024 and represents Newfoundland Power's forecast billing demand for 2024.

Newfoundland Power Inc.

Comparison of Forecast Energy Sales to Weather Adjusted Actual Sales

	Forecast Sales (GWh)	Weather Adjusted Actual Sales (GWh)	Difference (GWh)	Difference (%)
2013	5,763.6	5,763.3	-0.3	0.0
2014	5,835.6	5,898.5	62.9	1.1
2015	5,997.2	5,956.6	-40.6	-0.7
2016	5,990.5	5,950.1	-40.4	-0.7
2017	5,992.2	5,922.2	-70.0	-1.2
2018	5,915.0	5,876.1	-38.9	-0.7
2019	5,882.9	5,846.6	-36.3	-0.6
2020	5,793.0	5,729.0	-64.0	-1.1
2021	5,719.5	5,715.0	-4.5	-0.1
2022	5,699.3	5,784.5	85.2	1.5

The Conference Board of Canada
Provincial Medium-Term Economic Forecast,
August 2023

Table 1: Key Economic Indicators for Canada, 2023 to 2027
The Conference Board of Canada, *Provincial Medium-Term Economic Forecast*
August 2023

	2023	2024	2025	2026	2027
GDP at Market Prices (Millions $)	2,845,329	2,933,365	3,055,024	3,169,919	3,288,541
	2.3	*3.1*	*4.1*	*3.8*	*3.7*
GDP at Market Prices (Millions $2012)	2,204,722	2,229,507	2,284,655	2,332,660	2,380,375
	1.3	*1.1*	*2.5*	*2.1*	*2.0*
GDP at Basic Prices (Millions $2012)	2,084,045	2,108,223	2,161,374	2,208,319	2,254,162
	1.5	*1.2*	*2.5*	*2.2*	*2.1*
Implicit Price Deflator	1.3	1.3	1.3	1.4	1.4
GDP at Basic Prices (2012=1.0)	*0.9*	*1.9*	*1.6*	*1.6*	*1.7*
Consumer Price Index (2002=1.0)	1.6	1.6	1.6	1.7	1.7
	3.5	*2.3*	*2.0*	*2.0*	*2.0*
Wages and Salary per Employee (Thousands $)	62.7	64.6	66.2	67.7	69.2
	2.8	*3.0*	*2.5*	*2.3*	*2.3*
Primary Household Income (Millions $)	1,854,025	1,922,355	1,999,304	2,071,551	2,147,342
	4.4	*3.7*	*4.0*	*3.6*	*3.7*
Household Disposable Income (Millions $)	1,556,867	1,600,737	1,658,428	1,714,210	1,773,138
	2.4	*2.8*	*3.6*	*3.4*	*3.4*
Population of Labour Force Age	32,412	32,909	33,479	34,003	34,477
	2.0	*1.5*	*1.7*	*1.6*	*1.4*
Labour Force (000)	21,248	21,528	21,867	22,168	22,470
	2.2	*1.3*	*1.6*	*1.4*	*1.4*
Employment (000)	20,141	20,310	20,639	20,938	21,242
	2.2	*0.8*	*1.6*	*1.4*	*1.4*
Unemployment Rate	5.2	5.7	5.6	5.5	5.5
Retail Sales (Millions $)	794,706	812,730	837,766	862,941	888,358
	2.2	*2.3*	*3.1*	*3.0*	*2.9*
Housing Starts (Number of Units)	230,126	233,553	232,628	230,482	227,235
	-12.1	*1.5*	*-0.4*	*-0.9*	*-1.4*

Table 2: Key Economic Indicators for Newfoundland and Labrador, 2023 to 2027
The Conference Board of Canada, *Provincial Medium-Term Economic Forecast*
August 2023

	2023	2024	2025	2026	2027
GDP at Market Prices (Millions $)	40,522	40,865	41,390	41,681	42,448
	-5.9	*0.8*	*1.3*	*0.7*	*1.8*
GDP at Market Prices (Millions $2012)	32,510	33,038	33,504	33,888	34,493
	-0.2	*1.6*	*1.4*	*1.1*	*1.8*
GDP at Basic Prices (Millions $2012)	30,106	30,559	30,997	31,358	31,926
	-0.1	*1.5*	*1.4*	*1.2*	*1.8*
Implicit Price Deflator	1.2	1.2	1.2	1.2	1.2
GDP at Basic Prices (2012=1.0)	*-5.7*	*-0.8*	*-0.1*	*-0.4*	*0.1*
Consumer Price Index (2002=1.0)	1.6	1.6	1.7	1.7	1.7
	3.1	*2.3*	*1.9*	*2.0*	*2.0*
Wages and Salary per Employee (Thousands $)	60.2	62.0	63.5	64.7	66.0
	2.4	*3.0*	*2.3*	*1.9*	*2.0*
Primary Household Income (Millions $)	20,883	21,352	21,898	22,326	22,751
	3.0	*2.2*	*2.6*	*2.0*	*1.9*
Household Disposable Income (Millions $)	19,349	19,797	20,105	20,305	20,544
	4.3	*2.3*	*1.6*	*1.0*	*1.2*
Population of Labour Force Age	459	461	462	463	463
	2.0	*0.5*	*0.2*	*0.1*	*0.0*
Labour Force (000)	263	262	263	262	261
	0.3	*-0.1*	*0.2*	*-0.3*	*-0.4*
Employment (000)	236	233	234	234	233
	1.4	*-1.0*	*0.2*	*-0.1*	*-0.2*
Unemployment Rate	10.3	11.0	11.1	10.9	10.7
Retail Sales (Millions $)	11,563	11,720	11,861	11,975	12,081
	3.0	*1.4*	*1.2*	*1.0*	*0.9*
Housing Starts (Number of Units)	821	707	616	525	434
	-40.5	*-13.9*	*-12.9*	*-14.8*	*-17.3*

Cost of Service Study

NEWFOUNDLAND POWER
A FORTIS COMPANY

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Page

1.0 General

Cost of service studies are conducted on a regular basis to evaluate the reasonableness of cost recovery by class of service and as a step in the traditional process for establishing Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") customer rates.

In Newfoundland Power's *2003/2004 General Rate Application*, the Company presented detailed evidence on its cost of service study methodology. Through a mediation process, the parties at the hearing recommended the approval of the cost of service study methodology. In Order No. P.U. 19 (2003), the Board approved the recommendations as presented in the evidence and the Mediation Report.

In Order No. P.U. 32 (2007), the Board stated that it was satisfied that Newfoundland Power's cost of service study and methodology, along with the Marginal Cost Study, were appropriate to be used in establishing 2008 customer rates.

At Newfoundland Power's 2010, 2013/2014, 2016/2017, 2019/2020 and 2022/2023 general rate applications, the results of the Company's cost of service studies were accepted for use in establishing customer rates.

2.0 2022 *Pro Forma* Cost of Service Study

The Company has completed a 2022 *pro forma* Cost of Service Study (the "Cost of Service Study"). The detailed results of the Cost of Service Study are shown in Appendix A.

Table 1 provides the *pro forma* revenue-to-cost ratios.

Table 1:
Revenue-to-Cost Ratios
(%)

	2022 Pro Forma
Domestic	96.5
General Service	
(0-100kW)	107.9
(110-1000kVA)	107.5
(1000kVA and Over)	105.8
Street Lighting	97.2

The Cost of Service Study is based on actual costs and revenue incurred in 2022 adjusted to reflect the *pro forma* impact of the timing of the implementation of customer rates approved in the *2022/2023 General Rate Application* and cost of service changes related to the execution of the Company's *LED Street Lighting Replacement Plan*.[1]

3.0 Cost of Service Study Results

Appendix A shows the detailed results of the Cost of Service Study.

The results of the Cost of Service Study have been divided into the following five groups of schedules:

Group 1: Results, pages 2 to 14 of 43.

Group 2: Functional Classification of Rate Base, pages 15 to 22 of 43.

Group 3: Functional Classification of Expenses, pages 23 to 29 of 43.

Group 4: Determination of Class Allocation Factors, pages 30 to 38 of 43.

Group 5: Miscellaneous Schedules, pages 39 to 43 of 43.

3.1 Group 1: Results

Schedule 1.1 shows the major components that make up the total cost of service (excluding rate stabilization costs, municipal taxes and the rural deficit funding). The major components include purchased power expenses,[2] operating and maintenance expenses, depreciation expenses, expense credits and return and taxes. The schedule shows the breakdown of these cost components into the various functional classification groups used in the study. Expense credits include revenue that is either not generated from rates or is recovered through the RSA and is associated with particular functional classification groups.

Schedule 1.2 provides the cost by each functional classification group and the amount allocated to each class of service. The costs do not include rate stabilization costs, municipal taxes or the rural deficit funding.

Schedule 1.3 shows the total cost of service by class of service including rate stabilization costs, municipal taxes and the rural deficit funding. The schedule also subtracts other revenue from total costs to provide a column representing the total costs recovered from final customer rates.

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[1] In Order No. P.U. 3 (2022), the Board approved rates, tolls and charges as set out in Schedule A of the Application with effect for service provided on and after March 1, 2022. The 2022 Cost of Service Study includes *pro forma* adjustments to reflect: (i) a full year impact of that rate change; (ii) changes in rates due to the RSA and MTA with effect on July 1, 2023; and (iii) the forecast cost of service once all HPS street lights fixtures have been replaced with energy-efficient LED fixtures in 2026.

[2] The purchased power expense excludes the portion of the expense that is attributed to funding Newfoundland and Labrador Hydro's ("Hydro") rural deficit.

Schedule 1.4 shows the revenue attributed to each class of service. The schedule shows all the components that make up the total billings to customers plus other revenue. The other revenue amount excludes the revenue treated as expense credits in Schedule 1.1. Other revenue is attributed to each class of service based on the total revenue from base rates by class.

Schedule 1.5 compares the revenue by class to the cost by class and shows the revenue-to-cost ratios for each class of service. The costs from Schedule 1.3 and the revenues from Schedule 1.4 are used to compute the revenue-to-cost ratios.

Schedule 1.6 provides rate loaders that, when applied to the classified cost components (demand, energy, customer and specifically assigned costs), result in costs that can be compared to final customer rate components. The rate loaders are applied to each of the classified cost components. The RSA loader is added to the classified energy costs.

Schedule 1.7 expresses the cost of service in terms of unit costs. The unit costs provided are the $ per kW/kVA for demand costs, ¢/kWh for energy costs, and $/bill for customer-related costs. Also provided is a breakdown of demand and customer costs in ¢/kWh and an overall total cost expressed in terms of ¢/kWh.

3.2 Group 2: Functional Classification of Rate Base

Schedule 2.1 shows the original cost of the Company's fixed assets and its breakdown by the various functional classification categories. The total cost is based on the average amount of fixed assets employed during the year.

Schedule 2.2 shows the average accumulated depreciation and its breakdown into functional classification categories.

Schedule 2.3 shows the net contributions in aid of construction ("CIAC"). The net CIAC is the total CIAC received from customers and governments, less the CIAC amortized to date.

Schedule 2.4 shows the average rate base. The average rate base includes the total net utility plant, deductions from rate base and additions to rate base.[3] The net utility plant is the original cost of the fixed assets (Schedule 2.1) less the accumulated depreciation (Schedule 2.2).

3.3 Group 3: Functional Classification of Expenses

Schedule 3.1 shows the Company's expenses, both regulated and non-regulated, by cost of service expense category.

Schedule 3.2 shows the functional classification of the Company's expenses by expense category as follows:

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[3] The deductions from average rate base include the net CIAC (Schedule 2.3), customer security deposits, post-retirement benefits liability, future income taxes, and the demand management incentive liability. The additions to average rate base include average deferred charges (mostly pension costs), unamortized cost recovery deferrals, customer financing programs, the balance in the weather normalization reserve, cash working capital allowance, and materials and supplies allowance.

1. Purchased Power Expense.[4]

2. Direct Operating and Maintenance Expenses. These expenses include those internal costs that can be directly placed into functional groups.

3. General System Expenses. These expenses include costs related to general operations, communications and the system control center.
4. Administration and General Expenses. These expenses include the costs of administration, human resources, information systems, finance and regulatory costs.

5. CDM Costs. These expenses include CDM general costs, CDM program costs and the costs associated with the Curtailable Service Option.

Schedule 3.3 shows the breakdown of depreciation expense, net of CIAC amortization, into functional classification categories.

3.4 Group 4: Determination of Class Allocation Factors

Schedule 4.1 shows the customer statistics used to develop the allocation factors. The customer statistics include: the number of customers; total energy sales; total billing demand (where applicable); the estimated class load factors based on non-coincident peak ("NCP"); and the estimated class load factors based on coincident peak ("1 CP"). Schedule 4.1 also shows the estimated class demands at time of class peak (NCP) and the estimated class demands at time of Hydro's system peak (1 CP).

Schedule 4.2 shows the loss factors that are used as an input in calculating the energy and demand allocation factors.

Schedule 4.3 shows the development of the allocation factors for customer-related costs. The allocation factor for each type of customer cost is based on a weighting factor and the number of customers. An allocation factor of 0.0% occurs in a number of instances, such as the allocation factor used to allocate customer-related secondary costs to transmission customers. This reflects the concept that a transmission customer (i.e. a customer that takes their electricity supply from the transmission system) is not responsible for any of the cost of the distribution secondary or distribution primary system.

Schedule 4.4 shows the development of the secondary, primary and transmission allocation factors for energy-related costs. The allocation factors are based on energy sales and losses. Three separate allocation factors are required to ensure that within the Cost of Service Study, a transmission customer is not allocated any of the cost of the distribution secondary or primary system and that a distribution primary customer is not allocated any of the cost of the distribution secondary system.

Schedule 4.5 shows the development of the NCP demand allocation factors. The allocation factors are based on the estimated class peak and the loss factors shown in Schedule 4.1 and

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[4] The expense shown in the schedule excludes the portion of the purchased power cost associated with funding Hydro's rural deficit.

Schedule 4.2 respectively. The table shows three sets of allocation factors that are used when allocating the demand-related cost associated with either the secondary, primary or transmission levels.

Schedule 4.6 shows the development of the 1 CP demand allocation factor. The allocation factors are based on the estimated class demand at time of system peak and the loss factors shown in Schedule 4.1 and Schedule 4.2, respectively. The table shows three sets of allocation factors that are used when allocating the demand-related cost associated with either the secondary, primary or transmission levels.

3.5 Group 5: Miscellaneous Schedules

Schedule 5.1 shows the functional classification splits used in the Cost of Service Study. The input data was primarily derived from a variety of functionalization and classification studies. The sources of each functionalization and classification split are detailed in the footnotes in Schedule 5.1.

Schedule 5.2 shows the reconciliation of the total expenses used in the Cost of Service Study to the *2022 Annual Report* to the Board.

Schedule 5.3 shows the reconciliation of the total revenue used in the Cost of Service Study to the *2022 Annual Report* to the Board.

Schedule 5.4 shows the reconciliation of the total return and taxes used in the Cost of Service Study to the *2022 Annual Report* to the Board.

Cost of Service Study

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Notes:

1 - Within the Schedules rows and columns may not add due to rounding.

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FUNCTIONAL CLASSIFICATION OF THE COST OF SERVICE
(All numbers are times $1,000)

Line No.	Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution										Customer Acc. & Cust. Serv.	Customer Specific	Revenue Related
						Substation	Primary		Transformers		Secondary		Services	Meters	St. Lighting			
						Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer			
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	Purchase Power	416,846	176,321	240,525	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Operating and Maintenance	77,122	5,786	8,369	6,915	6,194	10,380	6,093	2,481	965	2,595	1,523	7,661	1,380	1,829	14,373	41	536
3	Depreciation	71,291	5,267	3,526	9,862	7,521	12,851	7,547	4,470	1,738	3,213	1,887	3,766	3,133	3,912	2,538	60	0
	Expense Credits																	
	Wheeling Revenues																	
4	Transmission	507	0	0	507	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Distribution	258	0	0	0	0	162	95	0	0	0	0	0	0	0	0	0	0
6	Joint Use Revenue	2,483	0	0	0	0	1,251	735	0	0	313	184	0	0	0	0	0	0
7	Revenue from Temp. Service and Reconnects	62	0	0	0	0	0	0	0	0	0	0	62	0	0	0	0	0
8	Customer Service Fees	257	0	0	0	0	0	0	0	0	0	0	0	0	0	257	0	0
9	RSA Transfer - Energy Supply Cost Variance	3,814	0	3,814	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	RSA Transfer - CDM Revenue Deferral	3,709	0	3,709	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Total Expense Credits	11,090	0	7,523	507	0	1,414	830	0	0	313	184	62	0	0	257	0	0
12	Subtotal Expenses	554,168	187,373	244,897	16,270	13,716	21,817	12,810	6,951	2,703	5,495	3,226	11,366	4,514	5,741	16,654	100	536
13	Return and Taxes	104,461	7,669	7,638	14,825	12,660	18,916	11,233	7,610	2,991	4,729	2,808	3,554	2,250	5,387	2,102	93	(4)
14	Total Cost of Service (Excluding RSA, MTA, Rural Deficit)	658,629	195,042	252,535	31,095	26,376	40,733	24,043	14,561	5,694	10,224	6,035	14,920	6,764	11,128	18,756	194	533

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FUNCTIONAL CLASSIFICATION OF THE COST OF SERVICE

Line No.	Category	
1	Purchase Power	Taken from Schedule 3.2, Line 4. (Excludes the Rural Deficit of $61,762,933)
2	Operating and Maintenance	Taken from Schedule 3.2, Line 37 less Line 4. (Excludes non-regulated expenses of $3,234,464)
3	Depreciation	Taken from Schedule 3.3, Line 20
	Expense Credits	
	Wheeling Revenues	
4	Transmission	Allocated based on functional classification of Transmission O&M expenses excluding specifically assigned (Schedule 3.2, Line 7).
5	Distribution	Based on the functional classification of Primary Distribution (Schedule 3.2, Line 12, Columns F & G).
6	Joint Use Revenue	Based on the functional classification of Poles, Lines and Fittings (Schedule 3.2, Line 12).
7	Revenue from Temp. Service and Reconnects	Based on functional classification of Services (Schedule 3.2, Line 13).
8	Customer Service Fees	Functional classification based on 100% Customer Service/ Customer Accounting.
9	RSA Transfer - Energy Supply Cost Variance	Classified 100% to Energy
10	RSA Transfer - CDM Revenue Deferral	Classified 100% to Energy
11	Total Expense Credits	Sum of lines 4 through 10.
12	Subtotal Expenses	Total of Lines 1, 2, and 3, less Line 11. (See Schedule 5.2 for the reconcillation to Total Company Expenses as Reported.)
13	Return and Taxes	Functional Classification based on Total Average Rate Base, Schedule 2.4, Line 38. (See Schedule 5.4 for the reconcillation to total Company Return and Taxes as Reported.)
14	Total Cost of Service (Excluding RSA, MTA, Rural Subsidy)	Total of Lines 12 and 13.

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ALLOCATION OF THE COST OF SERVICE TO CLASS OF SERVICE
Total Cost of Service excludes RSA, MTA and Rural Deficit (All numbers are times $1,000)

Line No.	Class of Service	Rate Code	Total	Produced & Purchased Demand A	Produced & Purchased Energy B	Transmission Demand C	Distribution: Substation Demand D	Distribution: Primary Demand E	Distribution: Primary Customer F	Distribution: Transformers Demand G	Distribution: Transformers Customer H	Distribution: Secondary Demand I	Distribution: Secondary Customer J	Distribution: Services Customer K	Distribution: Meters Customer L	Distribution: St. Lighting Customer M	Customer Acc. & Cust. Serv. N	Specifically Assigned O	Revenue Related P
	Allocation Factors Used ==>			Transmission 1CP	Transmission Energy	Transmission 1CP	Primary NCP	Primary NCP	Weighted Customers	Secondary NCP	Weighted Customers	Secondary NCP	Weighted Customers	Weighted Customers	Weighted Customers		Weighted Customers		Revenue
	DOMESTIC																		
1	Domestic Regular	1.1	78,450	20,581	25,889	3,281	3,168	4,893	5,574	1,841	1,259	1,292	1,400	3,573	1,136	0	4,504	0	60
2	Domestic All Electric	1.1	359,885	113,825	129,365	18,147	14,211	21,946	15,356	8,256	3,469	5,797	3,855	9,842	3,129	0	12,407	0	280
3	Total Domestic	1.1	438,336	134,405	155,254	21,428	17,379	26,839	20,930	10,097	4,729	7,090	5,255	13,415	4,265	0	16,912	0	339
	GENERAL SERVICES																		
4	(0-10 kW)	2.1	12,009	2,474	3,918	394	405	625	1,119	235	303	165	281	717	593	0	769	0	10
5	(10-100 kW)	2.1	69,478	20,882	30,275	3,329	3,029	4,677	912	1,760	371	1,235	229	701	1,338	0	678	0	62
6	Total (0-100 kW)	2.1	81,487	23,356	34,193	3,724	3,434	5,303	2,031	1,995	674	1,401	510	1,419	1,931	0	1,446	0	72
	(110-1000 kVA)	2.3																	
7	Primary (110-350 kVA)		881	265	443	42	41	63	1	0	0	0	0	0	25	0	1	0	1
8	Secondary (110-350 kVA)		45,640	13,367	22,204	2,131	2,061	3,182	84	1,197	57	841	21	86	304	0	63	0	42
9	Transmission (350-1000 kVA)		21	5	9	1	0	0	0	0	0	0	0	0	6	0	0	0	0
10	Primary (350-1000 kVA)		7,939	2,438	4,076	389	376	580	4	0	0	0	0	0	67	0	3	0	7
11	Secondary (350-1000 kVA)		37,665	11,146	18,514	1,777	1,718	2,653	20	998	14	701	5	0	72	0	15	0	32
12	Total (110-1000 kVA)	2.3	92,147	27,221	45,245	4,340	4,195	6,479	109	2,195	71	1,541	26	86	474	0	81	0	82
	(1000 kVA and Over)	2.4																	
13	Transmission		1,505	465	857	74	0	0	0	0	0	0	0	0	6	0	0	100	1
14	Primary		21,054	6,243	11,351	995	897	1,385	2	0	0	0	0	0	67	0	2	93	19
15	Secondary		9,405	2,698	4,874	430	387	598	3	225	2	158	1	0	20	0	2	0	8
16	Total (1000 kVA and Over)	2.4	31,964	9,406	17,083	1,500	1,284	1,983	5	225	2	158	1	0	93	0	4	193	28
17	**STREET LIGHTING**	4.1	14,694	653	761	104	83	129	968	48	219	34	243	0	0	11,128	313	0	11
18	Total		658,629	195,042	252,535	31,095	26,376	40,733	24,043	14,561	5,694	10,224	6,035	14,920	6,764	11,128	18,756	194	533

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ALLOCATION OF THE COST OF SERVICE TO CLASS OF SERVICE

NOTES:

Line No.	Category	
18	Total	Total Cost of Service shown in Schedule 1.1, Line 14

Column

A	Produced and Purchased Demand	Transmission demand Allocator for 1CP taken From Schedule 4.6, Column L.
B	Produced and Purchased Energy	Transmission Energy Allocator taken From Schedule 4.4, Column L.
C	Transmission Demand	Transmission demand Allocator for 1CP taken From Schedule 4.6, Column L.
D	Distribution Substation Demand	Primary demand Allocator for NCP taken from Schedule 4.5, Column H.
E	Distribution Primary Demand	Primary demand Allocator for NCP taken from Schedule 4.5, Column H.
F	Distribution Primary Customer	Primary Lines Customer Allocator taken from Schedule 4.3, Column G.
G	Distribution Transformer Demand	Secondary demand Allocator for NCP taken from Schedule 4.5, Column D.
H	Distribution Transformer Customer	Transformer Customer Allocator taken from Schedule 4.3, Column M.
I	Distribution Secondary Demand	Secondary demand Allocator for NCP taken from Schedule 4.5, Column D.
J	Distribution Secondary Customer	Secondary Lines Customer Allocator taken from Schedule 4.3, Column J.
K	Distribution Services Customer	Service Drop Allocator taken from Schedule 4.3, Column P.
L	Distribution Meters Customer	Meters Allocator taken from Schedule 4.3, Column S.
M	Distribution Street Lighting Customer	All Allocated to Street Lighting Rate Class.
N	Cust. Accounting and Cust. Services	Customer Allocator taken from Schedule 4.3, Column D.
O	Specifically Assigned	Total cost are allocated to class based on the amount of fixed plant dedicated to supplying single customers and the class which those customers belong.
P	Revenue Related	Total cost is allocated based on revenue from class plus RSA and MTA revenue, Column I, from Schedule 1.4.

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TOTAL ALLOCATION OF THE COST OF SERVICE
(All dollars are times $1,000)

Line No.	Class of Service	Rate Code	Energy A	Demand B	Customer C	Street Lighting D	Specifically Assigned E	Revenue Related Expenses F	Total before RSA, MTA and Rural Deficit G	Allocated Rural Subsidy H	MTA I	RSA J	Total Cost to Serve K	Allocation of Other Revenue L	Total Cost Recovered in Final Rates M
	DOMESTIC														
1	Domestic Regular	1.1	25,889	35,055	17,446	0	0	60	78,450	7,357	2,170	6,964	94,941	364	94,578
2	Domestic All Electric	1.1	129,365	182,182	48,059	0	0	280	359,885	33,748	10,205	34,763	438,602	1,701	436,901
3	Total Domestic	1.1	155,254	217,237	65,505	0	0	339	438,336	41,105	12,374	41,728	533,543	2,065	531,478
	GENERAL SERVICE														
4	(0-10 kW)	2.1	3,918	4,300	3,782	0	0	10	12,009	1,126	353	1,060	14,548	60	14,489
5	(10-100 kW)	2.1	30,275	34,912	4,229	0	0	62	69,478	6,515	2,265	8,203	86,461	375	86,086
6	Total (0-100 kW)	2.1	34,193	39,212	8,011	0	0	72	81,487	7,641	2,618	9,263	101,010	435	100,575
	(110-1000 kVA)	2.3													
7	Primary (110-350 kVA)		443	411	27	0	0	1	881	83	29	121	1,114	5	1,109
8	Secondary (110-350 kVA)		22,204	22,779	616	0	0	42	45,640	4,280	1,520	6,028	57,468	250	57,219
9	Transmission (350-1000 kVA)		9	6	6	0	0	0	21	2	1	1	24	0	24
10	Primary (350-1000 kVA)		4,076	3,783	73	0	0	7	7,939	745	265	1,113	10,062	43	10,019
11	Secondary (350-1000 kVA)		18,514	18,993	126	0	0	32	37,665	3,532	1,183	5,024	47,405	193	47,212
12	Total (110-1000 kVA)	2.3	45,245	45,972	848	0	0	82	92,147	8,641	2,999	12,287	116,074	491	115,583
	(1000 kVA and Over)	2.4													
13	Transmission		857	539	6	0	100	1	1,505	141	54	244	1,945	9	1,936
14	Primary		11,351	9,520	71	0	93	19	21,054	1,974	692	3,189	26,909	112	26,798
15	Secondary		4,874	4,497	26	0	0	8	9,405	882	286	1,209	11,782	47	11,736
16	Total (1000 kVA and Over)	2.4	17,083	14,556	104	0	193	28	31,964	2,997	1,033	4,642	40,636	167	40,469
17	**STREET LIGHTING**	4.1	761	1,052	1,742	11,128	0	11	14,694	1,378	389	213	16,674	70	16,604
18	Total		252,535	318,029	76,210	11,128	194	533	658,629	61,763	19,413	68,133	807,937	3,227	804,709

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TOTAL ALLOCATION OF THE COST OF SERVICE

NOTES:

Column	
A	Energy cost taken from Schedule 1.2, Column B.
B	Demand cost taken from Schedule 1.2, as the sum of Columns A, C, D, E, G and I.
C	Customer cost taken from Schedule 1.2, as the sum of Columns F, H, J, K, L and N.
D	Direct Street Lighting Cost taken from Schedule 1.2, Column M.
E	Specifically assigned cost taken from Schedule 1.2, Column O.
F	Revenue Related Expenses taken from Schedule 1.2, Column P.
G	Sum of Columns A through F.
H	Rural Surcharge allocated to Class based on total cost before Rural Deficit, RSA & MTA, Column G.
I	MTA cost taken as equal to MTA revenue as taken from Schedule 1.4 Column G.
J	RSA cost taken as equal to revenue from RSA factor from Schedule 1.4 Column F.
K	Sum of Columns G through J.
L	Taken from the sum of Schedule 1.4, Column C.
M	Column K less Column L.

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REVENUE BY CLASS OF SERVICE
(All dollars are times $1,000)

Line No.	Class of Service	Rate Code	Revenue from Base Rates: Base Rates A	Revenue from Base Rates: Forfeited Discounts B	Allocation of Other Revenue C	Remove Rural Subsidy D	Total Before Rural Subsidy E	RSA Revenue F	MTA Revenue G	Rural Subsidy H	Total Revenue + RSA & MTA I	Total Revenue from Final Rates J
	DOMESTIC											
1	Domestic Regular	1.1	80,461	348	364	(7,357)	73,816	6,964	2,170	7,357	90,306	89,943
2	Domestic All Electric	1.1	376,402	1,639	1,701	(33,748)	345,993	34,763	10,205	33,748	424,709	423,008
3	Total Domestic		456,862	1,986	2,065	(41,105)	419,809	41,728	12,374	41,105	515,016	512,951
	GENERAL SERVICE											
4	(0-10 kW)	2.1	13,175	48	60	(1,126)	12,157	1,060	353	1,126	14,696	14,637
5	(10-100 kW)	2.1	83,153	264	375	(6,515)	77,277	8,203	2,265	6,515	94,260	93,885
6	Total (0-100 kW)	2.1	96,329	312	435	(7,641)	89,434	9,263	2,618	7,641	108,956	108,521
	(110-1000 kVA)	2.3										
7	Primary (110-350 kVA)		1,054	5	5	(83)	980	121	29	83	1,213	1,208
8	Secondary (110-350 kVA)		55,297	156	250	(4,280)	51,422	6,028	1,520	4,280	63,250	63,000
9	Transmission (350-1000 kVA)		40	0	0	(2)	39	1	1	2	42	42
10	Primary (350-1000 kVA)		9,602	17	43	(745)	8,919	1,113	265	745	11,042	10,998
11	Secondary (350-1000 kVA)		42,749	98	193	(3,532)	39,508	5,024	1,183	3,532	49,247	49,054
12	Total (110-1000 kVA)	2.3	108,742	276	491	(8,641)	100,867	12,287	2,999	8,641	124,794	124,303
	(1000 kVA and Over)	2.4										
13	Transmission		1,945	14	9	(141)	1,827	244	54	141	2,267	2,258
14	Primary		24,759	28	112	(1,974)	22,924	3,189	692	1,974	28,780	28,668
15	Secondary		10,351	28	47	(882)	9,544	1,209	286	882	11,922	11,875
16	Total (1000 kVA and Over)	2.4	37,056	70	167	(2,997)	34,296	4,642	1,033	2,997	42,968	42,801
17	**STREET LIGHTING**	4.1	15,531	0	70	(1,378)	14,223	213	389	1,378	16,203	16,133
18	Total		714,520	2,644	3,227	(61,763)	658,628	68,133	19,413	61,763	807,936	804,709

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REVENUE BY CLASS OF SERVICE

NOTE:
Column

A - From Booked Revenue and Bill Frequency Analysis using March 1, 2022 rates for January through December.
B - From Booked Revenue and Bill Frequency Analysis using March 1, 2022 rates for January through December.
C - Includes Other Revenue as reported in Return 14 of the Annual Report to the Board ($13,620) less Expense Credits in Schedule 1.1 lines 4 through 8 ($3,567) and Other Contract Expenses from Return 20 of the Annual Report to the Board ($6,826).
D - The rural deficit cost is removed from revenue by allocating the cost to each customer class based on class cost as shown on Schedule 1.3 Column H.
E - Total of Columns A through D.
F - From actual RTA booked and Bill Frequency Analysis, using July 1, 2023 rates for January through December.
G - From actual MSA booked and Bill Frequency Analysis, using July 1, 2023 rates for January through December.
H - From Column D.
I - Total of Columns E through H.
J - Column I less Column C.

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REVENUE TO COST RATIO
Including RSA, MTA and Rural Subsidy
(All dollars are times $1,000)

Line No.	Class of Service	Rate	Revenue from Final Rates A	Costs B	Revenue to Cost Ratio C
1	**DOMESTIC**	1.1	512,950	531,477	96.5%
	GENERAL SERVICE				
2	(0-100 kW)	2.1	108,521	100,575	107.9%
3	(110 - 1000 kVA)	2.3	124,303	115,583	107.5%
4	(1000 kVA and Over)	2.4	42,801	40,469	105.8%
5	**STREET LIGHTING**	4.1	16,133	16,604	97.2%
6	Total		804,709	804,709	100.0%

Column
A Revenue from Schedule 1.4, Column J.
B Costs from Schedule 1.3, Column M.
C Column A divided by Column B.

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CLASSIFIED COST LOADERS BY CLASS
(All dollars are times $1,000)

			% Loader to be assigned to each Classified Cost Component							RSA Cost Loader (cents/kWh)		
Line No.	Class of Service	Rate Code	Rural Subsidy A	Revenue Related Costs B	Non-Rate Revenue Recovery C	MTA D	Total Costs in Loader E	Total Classified Costs F	% Rate Loader G	RSA H	Sales MWh I	RSA cents/kWh J
	DOMESTIC											
1	Domestic Regular	1.1	7,357	60	(364)	2,170	9,222	78,391	12%	6,964	591,644	1.18
2	Domestic All Electric	1.1	33,748	280	(1,701)	10,205	42,532	359,605	12%	34,763	2,956,337	1.18
3	Total Domestic	1.1	41,105	339	(2,065)	12,374	51,754	437,996	12%	41,728	3,547,981	1.18
	GENERAL SERVICE											
4	(0-10 kW)	2.1	1,126	10	(60)	353	1,429	11,999	12%	1,060	89,530	1.18
5	(10-100 kW)	2.1	6,515	62	(375)	2,265	8,467	69,416	12%	8,203	691,867	1.19
6	Total (0-100 kW)	2.1	7,641	72	(435)	2,618	9,896	81,416	12%	9,263	781,397	1.19
	(110-1000 kVA)	2.3										
7	Primary (110-350 kVA)		83	1	(5)	29	108	881	12%	121	10,180	1.19
8	Secondary (110-350 kVA)		4,280	42	(250)	1,520	5,592	45,599	12%	6,028	507,422	1.19
9	Transmission (350-1000 kVA)		2	0	(0)	1	3	21	12%	2	204	1.19
10	Primary (350-1000 kVA)		745	7	(43)	265	974	7,932	12%	1,113	93,711	1.19
11	Secondary (350-1000 kVA)		3,532	32	(193)	1,183	4,555	37,633	12%	5,023	423,089	1.19
12	Total (110-1000 kVA)	2.3	8,641	82	(491)	2,999	11,231	92,065	12%	12,287	1,034,606	1.19
	(1000 kVA and Over)	2.4										
13	Transmission		141	1	(9)	54	188	1,503	13%	244	20,175	1.21
14	Primary		1,974	19	(112)	692	2,573	21,035	12%	3,189	261,005	1.22
15	Secondary		882	8	(47)	286	1,130	9,397	12%	1,209	111,387	1.09
16	Total (1000 kVA and Over)	2.4	2,997	28	(167)	1,033	3,891	31,936	12%	4,642	392,568	1.18
17	**STREET LIGHTING**	4.1	1,378	11	(70)	389	1,708	14,684	12%	213	17,400	1.22
18	Total		61,763	533	(3,227)	19,413	78,481	658,097	12%	68,133	5,773,952	1.18

Newfoundland Power Inc.
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CLASSIFIED COST LOADERS BY CLASS

NOTE:

Column

A - See Schedule 1.3, Column H.
B - See Schedule 1.3, Column F.
C - See Schedule 1.3, Column L. (Negative).
D - See Schedule 1.3, Column I.
E - Total of Columns A through D.
F - See Schedule 1.3, Sum of Columns A through E.
G - Column E divided by Column F.
H - See Schedule 1.3, Column J.
I - See Schedule 4.1, Column D.
J - Column H divided by Column I.

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UNIT COSTS BY ENERGY, DEMAND AND CUSTOMER COSTS

Line No.	Class of Service	Rate Code	Billing Statistics From Schedule 4.1: Energy Sales MWh A	Billing Statistics From Schedule 4.1: Average Number of Customers B	Billing Statistics From Schedule 4.1: Total Billing Demands kW - kVA C	Unit Energy Costs cent/kWh D	Unit Demand Costs: By Energy Sales cent/kWh E	Unit Demand Costs: By Billing Demand $/kW - $/kVA F	Unit Customer Costs: By Energy Sales cent/kWh G	Unit Customer Costs: By Number of Customers $/Cust/month H	Specifically Assigned / Street Lighting Cost by Sales cent/kWh I	Total Cost by Sales cent/kWh J
	DOMESTIC											
1	Domestic Regular	1.1	591,644	63,274	0	6.068	6.622	0.00	3.296	25.68	0.000	15.986
2	Domestic All Electric	1.1	2,956,337	174,301	0	6.069	6.891	0.00	1.818	25.69	0.000	14.778
3	Total Domestic	1.1	3,547,981	237,575	0	6.069	6.846	0.00	2.064	25.69	0.000	14.980
	GENERAL SERVICE											
4	(0-10 kW)	2.1	89,530	12,702	0	6.081	5.375	0.00	4.728	27.77	0.000	16.183
5	(10-100 kW)	2.1	691,867	10,351	2,639,541	6.095	5.662	14.84	0.686	38.20	0.000	12.443
6	Total (0-100 kW)	2.1	781,397	23,053	2,639,541	6.093	5.628	14.84	1.150	32.48	0.000	12.871
	(110-1000 kVA)	2.3										
7	Primary (110-350 kVA)		10,180	15	28,598	6.070	4.531	16.13	0.296	167.53	0.000	10.898
8	Secondary (110-350 kVA)		507,422	957	1,658,909	6.100	5.040	15.42	0.136	60.21	0.000	11.276
9	Transmission (350-1000 kVA)		204	2	5,470	5.953	3.261	1.21	3.354	284.56	0.000	12.568
10	Primary (350-1000 kVA)		93,711	41	250,208	6.071	4.533	16.98	0.088	167.57	0.000	10.692
11	Secondary (350-1000 kVA)		423,089	228	1,181,533	6.093	5.033	18.02	0.033	51.68	0.000	11.159
12	Total (110-1000 kVA)	2.3	1,034,606	1,243	3,124,718	6.094	4.986	16.51	0.092	63.82	0.000	11.172
	(1000 kVA and Over)	2.4										
13	Transmission		20,175	2	58,717	5.989	3.009	10.34	0.036	302.28	0.560	9.594
14	Primary		261,005	27	576,948	6.103	4.094	18.52	0.031	246.77	0.040	10.267
15	Secondary		111,387	29	344,778	5.987	4.522	14.61	0.027	84.83	0.000	10.536
16	Total (1000 kVA and Over)	2.4	392,568	58	980,443	6.064	4.160	16.66	0.030	167.69	0.055	10.309
17	**STREET LIGHTING**	4.1	17,400	10,984	0	6.107	6.751	0.00	11.176	14.75	71.394	95.428
18	Total		5,773,952	272,913	6,744,702	6.075	6.165		1.477	26.05	0.219	13.937

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UNIT COSTS BY ENERGY, DEMAND AND CUSTOMER COSTS

NOTE:
Column
A - See Schedule 4.1, Column D.
B - See Schedule 4.1, Column C.
C - See Schedule 4.1, Column E.
D - [(Total of Energy Related Costs (Schedule 1.3, Column A) divided by Energy Sales (Schedule 1.7, Column A)) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100] plus RSA Loader (Schedule 1.6, Column J).
E - Demand Related Costs (Schedule 1.3, Column B) divided by Energy Sales (Schedule 1.7, Column A) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100.
F - Demand Related Costs (Schedule 1.3, Column B) divided by Total Billing Demands (Schedule 1.7, Column C) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 1,000.
G - Customer Related Costs (Schedule 1.3, Column C) divided by Energy Sales (Schedule 1.7, Column A) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100.
H - Customer Related Costs (Schedule 1.3, Column C) divided by Average Number of Customers (Schedule 1.7, Column B) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 1,000 divided by 12.
I - Specifically Assigned Costs (Schedule 1.3 Column E) divided by Energy Sales (Schedule 1.7, Column A) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100.
J - Total of Columns D, E, G and I.

Newfoundland Power Inc.
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FUNCTIONAL CLASSIFICATION OF AVERAGE FIXED ASSETS
(All numbers are times $1,000)

Line No.	Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Primary Demand F	Primary Customer G	Transformers Demand H	Transformers Customer I	Secondary Demand J	Secondary Customer K	Services Customer L	Meters Customer M	St. Lighting Customer N	Cust. Acc. & Cust. Serv. O	Specifically Assigned P
1	Hydro Electric Production	227,280	103,776	123,504	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	41,429	41,429	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	182,261	0	0	181,463	0	0	0	0	0	0	0	0	0	0	0	798
	Substations																
4	Hydro Electric Production	11,119	5,077	6,042	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	2,091	2,091	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	83,366	0	0	83,085	0	0	0	0	0	0	0	0	0	0	0	281
7	Distribution	203,186	0	0	0	202,654	0	0	0	0	0	0	0	0	0	0	532
	Distribution																
8	Land and Land Clearing	42	0	0	0	0	20	12	0	0	5	3	0	0	2	0	0
9	Conductors, Poles and Fittings	855,423	0	0	0	0	411,582	241,723	0	0	102,896	60,431	0	0	38,791	0	0
10	Transformers	179,567	0	0	0	0	0	0	129,288	50,279	0	0	0	0	0	0	0
11	Services	122,592	0	0	0	0	0	0	0	0	0	0	122,592	0	0	0	0
12	Meters	33,450	0	0	0	0	0	0	0	0	0	0	0	33,450	0	0	0
13	Street Lighting	41,508	0	0	0	0	0	0	0	0	0	0	0	0	41,508	0	0
14	Total Direct Utility Plant	1,983,313	152,373	129,546	264,547	202,654	411,602	241,735	129,288	50,279	102,901	60,434	122,592	33,450	80,302	0	1,611
	General Utility Plant																
15	Land and Land Clearing	4,587	282	240	662	364	739	434	232	90	185	109	220	60	144	822	4
16	Buildings	51,409	3,153	2,680	7,689	4,234	8,599	5,050	2,701	1,050	2,150	1,262	2,561	699	1,678	7,862	42
17	Computer Equipment	57,333	2,463	2,094	6,442	3,728	7,573	4,447	2,379	925	1,893	1,112	2,255	615	1,477	19,893	36
18	Misc. Equipment	13,712	732	622	2,642	1,173	2,383	1,399	748	291	596	350	710	194	465	1,394	14
19	Transportation	35,859	602	512	4,909	4,032	8,189	4,809	2,572	1,000	2,047	1,202	2,439	665	1,598	1,251	31
20	Tele-communications	7,867	490	416	2,292	640	1,299	763	408	159	325	191	387	106	253	127	11
21	Total General Utility Plant	170,768	7,722	6,565	24,636	14,170	28,781	16,903	9,040	3,516	7,195	4,226	8,572	2,339	5,615	31,349	138
22	Total	2,154,081	160,095	136,111	289,183	216,824	440,384	258,638	138,329	53,794	110,096	64,659	131,164	35,789	85,917	31,349	1,749

Newfoundland Power Inc.
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FUNCTIONAL CLASSIFICATION OF AVERAGE FIXED ASSETS

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Common costs classified based on the transmission common as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on Schedule 5.1 line 20 and classified as shown in Schedule 5.1 line 4.
5	Other Production	Functional splits on based Schedule 5.1 line 20 and classified as shown in Schedule 5.1 line 5.
6	Transmission	Functional splits based on Schedule 5.1 line 20 and common transmission costs classified as shown in Schedule 5.1 line 6.
7	Distribution	Functional splits based on Schedule 5.1 line 20 and distribution substation common costs classified as shown in Schedule 5.1 line 7.
	Distribution	
8	Land and Land Clearing	Functional splits based on Schedule 5.1 line 21 and classified as shown in Schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on Schedule 5.1 line 22 and classified as shown in Schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in Schedule 5.1 line 14.
11	Services	Classified as shown in Schedule 5.1 line 15.
12	Meters	Classified as shown in Shedule 5.1 line 16.
13	Street Lighting	Classified as shown in Schedule 5.1 line 17.
14	Total Direct Fixed Plant	Total of Lines 1 through 13.
	General Utility Plant	
15	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Misc. Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
21	Total General Property	Total of Lines 15 through 20.
22	Total	Total of Lines 14 and 21.

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FUNCTIONAL CLASSIFICATION OF AVERAGE ACCUMULATED DEPRECIATION
(All numbers are times $1,000)

Line No.	Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Distribution: Primary Demand F	Distribution: Primary Customer G	Distribution: Transformers Demand H	Distribution: Transformers Customer I	Distribution: Secondary Demand J	Distribution: Secondary Customer K	Distribution: Services Customer L	Distribution: Meters Customer M	Distribution: St. Lighting Customer N	Cust. Acc. & Cust. Serv. O	Specifically Assigned P
1	Hydro Electric Production	86,148	39,335	46,813	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	25,298	25,298	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	79,589	0	0	79,241	0	0	0	0	0	0	0	0	0	0	0	348
	Substations																
4	Hydro Electric Production	3,077	1,405	1,672	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	579	579	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	23,073	0	0	22,995	0	0	0	0	0	0	0	0	0	0	0	78
7	Distribution	56,235	0	0	0	56,088	0	0	0	0	0	0	0	0	0	0	147
	Distribution																
8	Land and Land Clearing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Conductors, Poles and Fittings	386,269	0	0	0	0	185,677	109,048	0	0	46,419	27,262	0	0	17,863	0	0
10	Transformers	56,455	0	0	0	0	0	0	40,647	15,807	0	0	0	0	0	0	0
11	Services	87,623	0	0	0	0	0	0	0	0	0	0	87,623	0	0	0	0
12	Meters	6,908	0	0	0	0	0	0	0	0	0	0	0	6,908	0	0	0
13	Street Lighting	181	0	0	0	0	0	0	0	0	0	0	0	0	181	0	0
	General Plant																
14	Land and Land Rights	(11)	(1)	(1)	(2)	(1)	(2)	(1)	(1)	(0)	(0)	(0)	(1)	(0)	(0)	(2)	(0)
15	Buildings	16,246	996	847	2,430	1,338	2,717	1,596	853	332	679	399	809	221	530	2,484	13
16	Computer Equipment	27,768	1,193	1,014	3,120	1,806	3,668	2,154	1,152	448	917	539	1,092	298	716	9,635	17
17	Misc. Equipment	8,106	433	368	1,562	694	1,409	827	442	172	352	207	420	114	275	824	8
18	Transportation	17,974	302	257	2,460	2,021	4,105	2,411	1,289	501	1,026	603	1,223	334	801	627	15
19	Tele-communications	4,559	284	241	1,328	371	753	442	236	92	188	111	224	61	147	74	6
20	Total	886,078	69,824	51,211	113,134	62,316	198,326	116,477	44,621	17,352	49,581	29,119	91,391	7,936	20,511	13,642	634

Newfoundland Power Inc.
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FUNCTIONAL CLASSIFICATION OF AVERAGE ACCUMULATED DEPRECIATION

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Common costs classified based on the transmission common as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on Schedule 5.1 line 20 and classified as shown in Schedule 5.1 line 4.
5	Other Production	Functional splits on based Schedule 5.1 line 20 and classified as shown in Schedule 5.1 line 5.
6	Transmission	Functional splits based on Schedule 5.1 line 20 and common transmission costs classified as shown in Schedule 5.1 line 6.
7	Distribution	Functional splits based on Schedule 5.1 line 20 and distribution substation common costs classified as shown in Schedule 5.1 line 7.
	Distribution	
8	Land and Land Clearing	Functional splits based on Schedule 5.1 line 21 and classified as shown in Schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on Schedule 5.1 line 22 and classified as shown in Schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in Schedule 5.1 line 14.
11	Services	Classified as shown in Schedule 5.1 line 15.
12	Meters	Classified as shown in Schedule 5.1 line 16.
13	Street Lighting	Classified as shown in Schedule 5.1 line 17.
	General Plant	
14	Land and Land Rights	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
15	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Total	Total of Lines 1 through 19.

Newfoundland Power Inc.
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FUNCTIONAL CLASSIFICATION OF AVERAGE NET CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)
(All numbers are times $1,000)

Line No.	Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Primary Demand F	Primary Customer G	Transformers Demand H	Transformers Customer I	Secondary Demand J	Secondary Customer K	Services Customer L	Meters Customer M	St. Lighting Customer N	Cust. Acc. & Cust. Serv. O	Specifically Assigned P
1	Hydro Electric Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	1,093	0	0	1,088	0	0	0	0	0	0	0	0	0	0	0	5
	Substations																
4	Hydro Electric Production	142	65	77	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	27	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	1,065	0	0	1,061	0	0	0	0	0	0	0	0	0	0	0	4
7	Distribution	2,595	0	0	0	2,588	0	0	0	0	0	0	0	0	0	0	7
	Distribution																
8	Land and Land Clearing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Conductors, Poles and Fittings	34,676	0	0	0	0	16,684	9,799	0	0	4,171	2,450	0	0	1,572	0	0
10	Transformers	2,441	0	0	0	0	0	0	1,758	684	0	0	0	0	0	0	0
11	Services	1,316	0	0	0	0	0	0	0	0	0	0	1,316	0	0	0	0
12	Meters	1,006	0	0	0	0	0	0	0	0	0	0	0	1,006	0	0	0
13	Street Lighting	616	0	0	0	0	0	0	0	0	0	0	0	0	616	0	0
	General Plant																
14	Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Computer Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Misc. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Tele-communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total	44,976	92	77	2,149	2,588	16,684	9,799	1,758	684	4,171	2,450	1,316	1,006	2,189	0	15

FUNCTIONAL CLASSIFICATION OF AVERAGE NET CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Common costs classified based on the transmission common as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on Schedule 5.1 line 20 and classified as shown in Schedule 5.1 line 4.
5	Other Production	Functional splits on based Schedule 5.1 line 20 and classified as shown in Schedule 5.1 line 5.
6	Transmission	Functional splits based on Schedule 5.1 line 20 and common transmission costs classified as shown in Schedule 5.1 line 6.
7	Distribution	Functional splits based on Schedule 5.1 line 20 and distribution substation common costs classified as shown in Schedule 5.1 line 7.
8	Land and Land Clearing	Functional splits based on Schedule 5.1 line 21 and classified as shown in Schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on Schedule 5.1 line 22 and classified as shown in Schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in Schedule 5.1 line 14.
11	Services	Classified as shown in Schedule 5.1 line 15.
12	Meters	Classified as shown in Schedule 5.1 line 16.
13	Street Lighting	Classified as shown in Schedule 5.1 line 17.
	General Plant	
14	Land and Land Rights	Functionalized based on general property land and land rights (See Schedule 5.1 line 23. Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
15	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Total	Total of Lines 1 through 19.

FUNCTIONAL CLASSIFICATION OF AVERAGE RATE BASE
(All numbers are times $1,000)

Line No. Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution Substation Demand E	Distribution Primary Demand F	Distribution Primary Customer G	Distribution Transformers Demand H	Distribution Transformers Customer I	Distribution Secondary Demand J	Distribution Secondary Customer K	Distribution Services Customer L	Distribution Meters Customer M	Distribution St. Lighting Customer N	Cust. Acc. & Cust. Serv. O	Specifically Assigned P	Revenue Related Q
1 Hydro Electric Production	141,132	64,441	76,691	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Other Generation	16,131	16,131	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Transmission	102,672	0	0	102,222	0	0	0	0	0	0	0	0	0	0	0	450	0
Substations																	
4 Hydro Electric Production	8,041	3,672	4,370	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Other Production	1,512	1,512	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Transmission	60,293	0	0	60,089	0	0	0	0	0	0	0	0	0	0	0	203	0
7 Distribution	146,950	0	0	0	146,566	0	0	0	0	0	0	0	0	0	0	385	0
Distribution																	
8 Land and Land Clearing	42	0	0	0	0	20	12	0	0	5	3	0	0	2	0	0	0
9 Conductors, Poles and Fittings	469,154	0	0	0	0	225,905	132,675	0	0	56,476	33,169	0	0	20,929	0	0	0
10 Transformers	123,112	0	0	0	0	0	0	88,641	34,471	0	0	0	0	0	0	0	0
11 Services	34,969	0	0	0	0	0	0	0	0	0	0	34,969	0	0	0	0	0
12 Meters	26,542	0	0	0	0	0	0	0	0	0	0	0	26,542	0	0	0	0
13 Street Lighting	41,328	0	0	0	0	0	0	0	0	0	0	0	0	41,328	0	0	0
14 Total Direct Net Utility Plant	1,171,878	85,756	81,061	162,312	146,566	225,926	132,686	88,641	34,471	56,481	33,172	34,969	26,542	62,258	0	1,038	0
General Plant																	
15 Land and Land Rights	4,598	283	241	663	365	741	435	233	91	185	109	221	60	145	824	4	0
16 Buildings	35,164	2,156	1,833	5,259	2,896	5,881	3,454	1,847	718	1,470	864	1,752	478	1,147	5,378	29	0
17 Computer Equipment	29,566	1,270	1,080	3,322	1,923	3,905	2,293	1,227	477	976	573	1,163	317	762	10,258	19	0
18 Misc. Equipment	5,606	299	254	1,080	480	974	572	306	119	244	143	290	79	190	570	6	0
19 Transportation	17,884	300	255	2,448	2,011	4,084	2,399	1,283	499	1,021	600	1,216	332	797	624	15	0
20 Tele-communications	3,308	206	175	964	269	546	321	172	67	137	80	163	44	107	53	5	0
21 Total General Plant	96,126	4,515	3,839	13,737	7,943	16,132	9,474	5,067	1,971	4,033	2,369	4,805	1,311	3,147	17,707	77	0
22 Total Net Utility Plant	1,268,004	90,271	84,900	176,049	154,508	242,058	142,161	93,708	36,442	60,514	35,540	39,773	27,853	65,406	17,707	1,115	0
Deductions from Rate Base																	
23 Contributions in Aid of Construction	44,976	92	77	2,149	2,588	16,684	9,799	1,758	684	4,171	2,450	1,316	1,006	2,189	0	15	0
24 Security Deposits	1,336	101	85	139	118	214	126	56	22	53	31	113	18	69	191	1	0
25 Post Retirement Benefits Liability	82,093	6,209	5,234	8,521	7,235	13,149	7,722	3,426	1,332	3,287	1,931	6,928	1,126	4,213	11,723	56	0
26 Future Income Taxes - Depreciation/CCA	39,358	2,802	2,635	5,464	4,796	7,513	4,413	2,909	1,131	1,878	1,103	1,235	865	2,030	550	35	0
27 Future Income Taxes - Pension/OPEBS	(22,332)	(1,689)	(1,424)	(2,318)	(1,968)	(3,577)	(2,101)	(932)	(362)	(894)	(525)	(1,885)	(306)	(1,146)	(3,189)	(15)	0
28 Demand Management Incentive Liability	(618)	(618)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 Total Deductions	144,812	6,897	6,608	13,955	12,768	33,983	19,958	7,216	2,806	8,496	4,990	7,706	2,708	7,355	9,274	92	0
Additions to Rate Base																	
30 Average Deferred Charges	92,083	6,965	5,871	9,558	8,116	14,749	8,662	3,843	1,495	3,687	2,166	7,771	1,263	4,726	13,149	63	0
31 Unamortized Cost Recovery Deferrals	18,130	1,371	1,156	1,882	1,598	2,904	1,705	757	294	726	426	1,530	249	930	2,589	12	0
32 Customer Financing Programs	1,614	122	103	167	142	258	152	67	26	65	38	136	22	83	230	1	0
33 Weather Normalization (Hydro Equalization)	5,056	0	5,056	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34 Weather Normalization (Degree Day Norm.)	(9,354)	(935)	(879)	(1,823)	(1,600)	(2,507)	0	(971)	0	(627)	0	0	0	0	0	(12)	0
35 Cash Working Capital Allowance	6,705	497	1,474	589	504	903	530	245	95	226	132	449	81	276	743	4	(43)
36 Materials And Supplies	11,978	331	282	4,844	918	1,864	1,095	585	228	466	274	555	151	364	0	22	0
37 Total Additions	126,211	8,351	13,061	15,217	9,677	18,171	12,144	4,527	2,138	4,543	3,036	10,441	1,766	6,379	16,712	91	(43)
38 Total Average Rate Base	1,249,403	91,725	91,353	177,310	151,417	226,246	134,346	91,018	35,773	56,561	33,587	42,508	26,910	64,430	25,145	1,114	(43)

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FUNCTIONAL CLASSIFICATION OF AVERAGE RATE BASE

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
2	Other Generation	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
3	Transmission	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
	Substations	
4	Hydro Electric Production	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
5	Other Production	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
6	Transmission	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
7	Distribution	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
	Distribution	
8	Land and Land Clearing	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
9	Conductors, Poles and Fittings	
10	Transformers	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
11	Services	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
12	Meters	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
13	Street Lighting	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
14	Total Direct Net Utility Plant	Total of Lines 1 to 13.
	General Plant	
15	Land and Land Rights	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
16	Buildings	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
17	Computer Equipment	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
18	Misc. Equipment	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
19	Transportation	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
20	Tele-communications	Difference Between the Allocated Average Fixed Assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
21	Total General Plant	Total of Lines 15 to 20.
22	Total Net Utility Plant	Total of Line 14 and Line 21.
	Deductions from Rate Base	
23	Contributions in Aid of Construction	Taken from totals shown on Schedule 2.3.
24	Security Deposits	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
25	Post Retirement Benefits Liability	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
26	Future Income Taxes - Depreciation/CCA	Functional Classification based on Total Net Utility Plant (Line 22).
27	Future Income Taxes - Pension/OPEBS	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
28	DMI Liability	Functional Classification Classified 100% to Produced and Purchased Demand.
29	Total Deductions	Total of Lines 23 through 28.
	Additions to Rate Base	
30	Average Deferred Charges	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
31	Unamortized Cost Recovery Deferrals	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
32	Customer Financing Programs	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
33	Weather Normalization (Hydro Equalization)	Classified 100% to Energy.
34	Weather Normalization (Degree Day Norm.)	Functional Classification split based on Total Net Utility Plant (Line 22) excluding Customer Classification Functions.
35	Cash Working Capital Allowance	Functional Classification based on Adminsitration and General Expenses (See Schedule 3.2, Line 32) and CDM Actvities (See Schedule 3.2, Line 36)
36	Materials And Supplies	Functionalized based on Year End Inventory (See Schedule 5.1 Line 31). Classification based on total direct utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned (Schedule 2.1).
37	Total Additions	Total of Lines 30 through 36.
38	Total Rate Base	Line 22 less Line 29 plus Line 37.

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LIST OF OPERATING EXPENSES NET OF GENERAL EXPENSES TRANSFERRED TO CAPITAL (GEC)
(Excludes Rate Stabilization Account (RSA) & Municipal Tax Adjustment (MTA)
(All numbers are times $1,000)

Expense Category Code	Description	Including Non-Regulated Expenses			Non-Regulated	Excluding Non-Regulated Expenses		
		Total	Labour	Non-Labour	Expenses	Total Excl.	Labour Excl.	Non-Labour Excl.
	PURCHASED POWER WEATHER ADJUSTED							
PPH	Nfld. Hydro - Firm	478,608	0	478,608	0	478,608	0	478,608
PPDL	Nfld. Hydro - Secondary	0	0	0	0	0	0	0
	TOTAL PURCHASED POWER	478,608	0	478,608	0	478,608	0	478,608
	PRODUCTION							
	Steam Production							
Oth Prod	Steam - Direct Operating And Maintenance	0	0	0	0	0	0	0
Oth Prod	Steam - Fuel - Lubricants	0	0	0	0	0	0	0
Hydro	Hydro - Direct Operating and Maintenance	0	0	0	0	0	0	0
Hydro	Hydro - Water and Fuel - Lubricants	0	0	0	0	0	0	0
Hydro	Hydro - Supervision and Misc.	3,426	1,603	1,824	0	3,426	1,603	1,824
Oth Prod	Other Production - Direct Operating and Maintenance	581	309	272	0	581	309	272
Oth Prod	Other Production - Fuel and Lubricants	0	0	0	0	0	0	0
	TOTAL PRODUCTION	4,007	1,912	2,096	0	4,007	1,912	2,096
Gen Sys Opr	SYSTEM OPERATIONS	1,603	1,548	55	0	1,603	1,548	55
Gen PTD	TOOLS, SAFETY, EQUIPMENT REPAIR & RUBBER GLOVE TESTING	1,737	795	941	0	1,737	795	941
Gen PTD	GENERAL OPERATIONS	4,107	3,278	829	0	4,107	3,278	829
	TOTAL MISC. TECHNICAL OPERATING COSTS	7,447	5,621	1,825	0	7,447	5,621	1,825
Gen PTD	ENVIRONMENTAL COST	204	147	56	0	204	147	56
	SUBSTATIONS							
Subs	Direct O&M	2,318	1,650	669	0	2,318	1,650	669
	TRANSMISSION							
Transm	Direct O&M	1,143	357	786	0	1,143	357	786
	DISTRIBUTION							
CPF	Direct O&M - Lines/poles/fittings	4,086	3,638	448	0	4,086	3,638	448
Services	Direct O&M - Services	3,144	3,016	128	0	3,144	3,016	128
Strlgts	Direct O&M - Street Lights	276	156	120	0	276	156	120
Transf.	Direct O&M - Transformers	282	255	26	0	282	255	26
Meters	Direct O&M - Meters	452	362	90	0	452	362	90
Gen D	Direct O&M - Vegetation Management	2,518	294	2,225	0	2,518	294	2,225
Gen D	Distribution Line Inspections	304	293	10	0	304	293	10
Gen D	Pre Issues	264	0	264	0	264	0	264
	TOTAL DISTRIBUTION	11,325	8,013	3,312	0	11,325	8,013	3,312
	COMMUNICATIONS							
Gen Comm	Direct O&M - General	1,486	59	1,427	0	1,486	59	1,427
	TOTAL COMMUNICATIONS	1,486	59	1,427	0	1,486	59	1,427
	CUSTOMER SERVICE							
Cust Acc	Customer Service Administration, Billing & Meter Reading	2,051	1,742	308	99	1,951	1,658	294
Cust Acc	Credit, Collections & Cash Control	2,107	758	1,349		2,107	758	1,349
Cust Acc	Inquiry	3,865	3,749	116		3,865	3,749	116

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Cust Acc	Uncollectable Bills	2,027	0	2,027	0	2,027	0	2,027
CDM - GA	Conservation and Demand Management - General Activities	585	292	293		585	292	293
CDM - Prom	Conservation and Demand Management - Program Costs	8,965	1,901	7,063		8,965	1,901	7,063
CDM - Prom	Deferred Electrification Program Costs	(28)	0	(28)		(28)	0	(28)
CDM - DM	Curtailable Service Option	408	8	400		408	8	400
CDM - Prom	Conservation and Demand Management - Program Costs Deferred	(5,227)	(1,101)	(4,126)		(5,227)	(1,101)	(4,126)
			0	0				
	TOTAL CUSTOMER SERVICE	14,753	7,349	7,404	99	14,654	7,265	7,389
	FINANCE							
A&G	Finance	1,537	1,323	214		1,537	1,323	214
Labour Rela	Company Pension Scheme	(3,233)	0	(3,233)		(3,233)	0	(3,233)
Labour Rela	Other Post Retirement Benefits	6,283	0	6,283		6,283	0	6,283
	TOTAL FINANCE	4,587	1,323	3,264	0	4,587	1,323	3,264
A&G	CORPORATE COMMUNICATIONS	929	445	484	28	901	432	469
Cust Acc	Corporate Communications - Safety Advertisements	0	0	0	0	0	0	0
	TOTAL CORPORATE COMMUNICATIONS	929	445	484	28	901	432	469
			0	0				
	MANAGEMENT INFORMATION SYSTEMS		0	0				
A&G	Computer Operations	911	664	247	0	911	664	247
A&G	Systems Development and Support	5,519	1,990	3,529	0	5,519	1,990	3,529
	TOTAL MIS	6,430	2,654	3,776	0	6,430	2,654	3,776
	HUMAN RESOURCE AND EMPLOYEE RELATED COSTS							
A&G	Human Resources Division	2,585	1,949	636	0	2,585	1,949	636
A&G	Employee Welfare & Coffee & Lunchroom Supplies	158	3	155	0	158	3	155
	TOTAL HUMAN RESOURCE AND EMPLOYEE RELATED COSTS	2,743	1,952	791	0	2,743	1,952	791
	ADMINSTRATION & MISCELLANEOUS							
A&G	Administration, Support Staff and Internal Audit	10,967	6,906	4,061	2,861	8,106	5,105	3,002
A&G	Misc. Costs - General	3,468	980	2,489	247	3,222	910	2,312
Ins & Dam.	Misc. Costs - Property Insurance & Public Liability (Not Insured)	2,474	0	2,474	0	2,474	0	2,474
A&G	Amortization of Hearing Costs	0	0	0	0	0	0	0
Revenue Related	PUB Assessments	1,192	0	1,192	0	1,192	0	1,192
			0	0				
A&G	Property Maintenance	2,265	260	2,005	0	2,265	260	2,005
A&G	Printing Services	225	174	51	0	225	174	51
	TOTAL ADMINISTRATION & MISCELLANEOUS	20,618	8,320	12,298	3,108	17,511	6,449	11,062
Vehicles	VEHICLE MAINTENANCE	2,189	0	2,189	0	2,189	0	2,189
	TOTAL OPERATING AND MAINTENANCE EXPENSES Net of GEC & (Excluding RSA & MTA Expense)	558,788	39,803	518,985	3,234	555,553	37,834	517,719

Expense Category Code	Cost of Service Expense Category
A&G	Administration and General (Excluding Labour Related Costs).
CDM - GA	Conservation and Demand Management - General Activities.
CDM - Prom	Conservation and Demand Management - Program Costs.
CDM - DM	Curtailable Service Option and Voltage Management.
CPF	Operating expenses directly associated with Conductors, Poles and Fittings.
Cust Acc	Operating Expenses associated with Customer Accounting and Customer Service.
Gen Comm	Communication Expenses Related to the VHS/Mobile radio system.
Gen D	General expenses to be split over the categories within distribution.
Gen PTD	General expenses to be split over Production, Transmission and Distribution.
Gen Sys Opr	General expenses associated with the Systems Control Centre.
Hydro	Operating expenses associated with Hydraulic Generation.
Labour Rela	Administration and general Expenses directly related to Labour.
Meters	Operating expenses directly associated with Meters.
Oth Prod	Operating expenses associated with Diesel and Gas Turbine Generation.
Ins & Dam.	Property Insurance, Public Liability, Risk Management.
PPDL	Purchase Power Costs for Secondary Energy from Deer Lake Power Firmed up by Hydro.
PPH	Purchase Power Costs from Hydro for Firm Energy.
Revenue Related	Operating expenses related to revenue.
Services	Operating expenses directly associated with Services.
Strlgts	Operating expenses directly associated with Street Lighting.
Subs	Operating expenses directly associated with Substations.
Transf.	Operating expenses directly associated with Transformers.
Transm	Operating expenses directly associated with Transmission.
Vehicles	Operating expenses directly associated with Vehicles.

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FUNCTIONAL CLASSIFICATION OF OPERATING AND MAINTENANCE EXPENSES
(All numbers are times $1000)

Line No.	Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Distribution: Primary Demand F	Distribution: Primary Customer G	Distribution: Transformers Demand H	Distribution: Transformers Customer I	Distribution: Secondary Demand J	Distribution: Secondary Customer K	Distribution: Services Customer L	Distribution: Meters Customer M	Distribution: St. Lighting Customer N	Customer Acc. & Cust. Serv. O	Specifically Assigned P	Revenue Related Q
	Purchase Power Expense																	
1	Purchases from Hydro - Production related	365,812	125,287	240,525	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Purchases from Hydro - Transmission related	50,880	50,880	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Demand Management Incentive Account	153	153	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Sub Total	416,846	176,321	240,525	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Direct Operating & Maintenance Expense																	
5	Hydraulic Production	3,426	1,564	1,862	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Other Production	581	581	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Transmission	1,143	0	0	1,138	0	0	0	0	0	0	0	0	0	0	0	5	0
	Substations																	
8	Hydraulic Plants	86	39	47	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Other Production	16	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Transmission	645	0	0	643	0	0	0	0	0	0	0	0	0	0	0	2	0
11	Distribution	1,571	0	0	0	1,567	0	0	0	0	0	0	0	0	0	0	4	0
	Distribution																	
12	Lines/poles/fittings	4,086	0	0	0	0	2,059	1,209	0	0	515	302	0	0	0	0	0	0
13	Services	3,144	0	0	0	0	0	0	0	0	0	0	3,144	0	0	0	0	0
14	Street Lights	276	0	0	0	0	0	0	0	0	0	0	0	0	276	0	0	0
15	Transformers	282	0	0	0	0	0	0	203	79	0	0	0	0	0	0	0	0
16	Meters	452	0	0	0	0	0	0	0	0	0	0	0	452	0	0	0	0
17	Customer Accounting	9,977	0	0	0	0	0	0	0	0	0	0	0	0	0	9,977	0	0
18	Subtotal Direct O&M	25,685	2,201	1,909	1,781	1,567	2,059	1,209	203	79	515	302	3,144	452	276	9,977	11	0
	General System Expenses																	
19	Related to Distribution	3,086	0	0	0	456	802	471	203	79	200	118	517	96	143	0	1	0
20	Related to Prod, Trans. & Distribution	6,047	606	521	771	612	1,077	633	273	106	269	158	695	130	192	0	5	0
21	Related to Vehicles	2,189	37	31	300	246	500	294	157	61	125	73	149	41	98	76	2	0
22	System Control Centre Expenses	1,603	99	85	258	171	302	177	76	30	75	44	195	36	54	0	0	0
23	General Communication Expenses	1,486	46	39	215	142	249	146	63	25	62	37	161	30	44	227	0	0
24	Subtotal General System Expenses	14,411	788	677	1,543	1,627	2,930	1,721	772	300	732	430	1,716	333	530	303	8	0
	Administration and General																	
25	Insurance, Injuries & Damages	2,474	176	166	343	301	472	277	183	71	118	69	78	54	128	35	2	0
26	Labour Related	3,050	227	195	331	275	501	294	135	52	125	74	278	55	91	414	2	0
27	Other Administration And General Expenses	25,430	1,893	1,623	2,760	2,292	4,180	2,455	1,125	437	1,045	614	2,317	460	762	3,451	16	0
28	2022 Cost Deferral less 2022 Amortization	(656)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(656)
29	Pension and OPEBs Variance Deferral	832	62	53	90	75	137	80	37	14	34	20	76	15	25	113	1	0
30	PUB Assessments	1,192	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,192
31	Subtotal Administration and General Expenses	32,322	2,358	2,037	3,524	2,944	5,290	3,107	1,479	575	1,322	777	2,748	585	1,006	4,013	21	536
	CDM Activities																	
32	CDM - General Activities	585	44	37	63	53	96	56	26	10	24	14	53	11	18	79	0	0
33	CDM - Program Costs	3,709	0	3,709	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Curtailable Service Option	408	395	0	4	3	5	0	0	0	1	0	0	0	0	0	0	0
35	Subtotal CDM Activities	4,703	438	3,747	67	56	101	56	26	10	25	14	53	11	18	79	0	0
36	Total O&M (less RSA, MTA and Rural Deficit)	493,967	182,106	248,894	6,915	6,194	10,380	6,093	2,481	965	2,595	1,523	7,661	1,380	1,829	14,373	41	536

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FUNCTIONAL CLASSIFICATION OF OPERATING AND MAINTENANCE EXPENSES

Line No.	Column A - Total Category	From Schedule 3.1 less rural deficit plus regulatory deferrals (Lines 28 & 29) Basis for Functional Classification
	Purchase Power Expense	Excludes the rural deficit of $61,762,933
1	Purchases from Hydro - Production related	Based on functional classification splits shown in Schedule 5.1, Line 1. (Split between Hydro-Production and Hydro-Transmission based on split shown in Schedule 5.1, Line 18.
2	Purchases from Hydro - Transmission related	Based on functional classification splits shown in Schedule 5.1, Line 2. (Split between Hydro-Production and Hydro-Transmission based on split shown in Schedule 5.1, Line 18.
3	Demand Mangement Incentive Account	Classification based on 100% Purchase Power Demand
4	Sub Total	Total of Lines 1 to 3.
	Direct Operating & Maintenance Costs	
5	Hydraulic Production	Based on classification splits shown in Schedule 5.1, Line 4.
6	Other Production	Based on classification splits shown in Schedule 5.1, Line 5.
7	Transmission	Functional split based on Schedule 5.1 line 19. Classified based on the transmission general as shown on Schedule 5.1 Line 6.
	Substations	
8	Hydarulic Plants	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
9	Other Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
10	Transmission	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 6.
11	Distribution	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 7.
	Distribution	
12	Lines/poles/fittings	Functional splits based on schedule 5.1 line 22 (excluding street lighting) and classified as shown in schedule 5.1 lines 11 & 12.
13	Services	Classified as shown in schedule 5.1 line 15.
14	Street Lights	Classified as shown in schedule 5.1 line 17.
15	Transformers	Classified as shown in schedule 5.1 line 14.
16	Meters	Classified as shown in schedule 5.1 line 16.
17	Customer Accounting	Classified 100% to Customer Accounting (Customer).
18	Subtotal Direct O&M	Total of Lines, 5 to 17.
	General System Expenses	Functional Classification based on a weighted average total of the splits for fixed assets (Schedule 2.1, Line 22) and O&M (Schedule 3.2 Line 20). The weighting used is: 50.1% operating, and 49.9% capital.

	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution: Substation Demand	Primary Demand	Primary Customer	Transformers Demand	Transformers Customer	Secondary Demand	Secondary Customer	Services Customer	Meters Customer	St. Lighting Customer	Cust. Acc. & Cust. Serv.	Specifically Assigned	Revenue Related
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Weighted Splits	100.0%	8.0%	6.9%	10.2%	8.1%	14.2%	8.4%	3.6%	1.4%	3.6%	2.1%	9.2%	1.7%	2.5%	20.2%	0.1%	0.0%

Line No.	Category	Basis for Functional Classification
19	Related to Distribution	Functional Classification based on the weighted split shown for Columns E through N & the distribution portion of Column P.
20	Related to Prod, Trans. & Distribution	Functional Classification based on the weighted split shown for Columns B through N & P.
21	Related to Vehicles	Functional Classification based on splits for vehicle fixed assets (see schedule 2.4 line 19).
22	System Control Centre Expenses	Functionalized based on a study of SCADA plant (see Schedule 5.1, Line 29). Classification based on functional categories shown for general system expenses in columns B through N.
23	General Communications Expenses	Functionalized based on a study of Communications Expenses (see Schedule 5.1, Line 30). Classification based on functional categories shown for general system expenses in columns B through O.
24	Subtotal General System Expenses	Total of all Lines 19 to 23.
	Administration and General Expenses	Functional Classification based on a weighted average total of the splits for fixed assets (Schedule 2.1, Line 22) and O&M (Schedule 3.2 Lines 20 plus 26). The weighting used is: 50.1% operating, and 49.9% capital.

Split for Administration and General	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution: Substation Demand	Primary Demand	Primary Customer	Transformers Demand	Transformers Customer	Secondary Demand	Secondary Customer	Services Customer	Meters Customer	St. Lighting Customer	Cust. Acc. & Cust. Serv.	Specifically Assigned	Revenue Related
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Weighted Splits	100.0%	7.4%	6.4%	10.9%	9.0%	16.4%	9.7%	4.4%	1.7%	4.1%	2.4%	9.1%	1.8%	3.0%	13.6%	0.1%	0.0%

Line No.	Category	Basis for Functional Classification
25	Insurance, Injuries & Damages	Functional Classification based on Net Utility Plant in Service (See Schedule 2.4, Line 22)
26	Labour Related	Functional Classification based on the Weighted Split for Administration and General.
27	Other Administration And General Expenses	Functional Classification based on the Weighted Split for Administration and General.
28	Amortization - 2019 General Cost Deferral	Assigned 100% as Revenue Related.
29	Pension and OPEBs Variance Deferral	Functional Classification based on the Weighted Split for Administration and General.
30	PUB Assessments	Assigned 100% as Revenue Related.
31	Subtotal Administration and General	Total for Lines 25 to 31.
32	CDM - General Activities	Functional Classification based on the Weighted Split for Administration and General.
33	CDM - Program Costs	Functional Classification based 100% avoided energy supply cost
34	Curtaible Service Option	Functional Classification based on direct O&M classified to demand including purchase power.
35	Subtotal CDM Activities	Total for Lines 33 to 35
36	Total O&M	Totals of Lines 4, 18, 24, 32 and 36.

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FUNCTIONAL CLASSIFACTION OF DEPRECIATION EXPENSES (NET OF AMORTIZED CIAC)
(All numbers are times $1,000)

Line No.	Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution										Cust. Acc. & Cust. Serv.	Specifically Assigned
						Substation	Primary		Transformers		Secondary		Services	Meters	St. Lighting		
						Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer		
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Hydro Electric Production	5,415	2,473	2,943	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	2,106	2,106	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	5,638	0	0	5,613	0	0	0	0	0	0	0	0	0	0	0	25
	Substations																
4	Hydro Electric Production	360	164	195	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	68	68	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	2,696	0	0	2,687	0	0	0	0	0	0	0	0	0	0	0	9
7	Distribution	6,571	0	0	0	6,554	0	0	0	0	0	0	0	0	0	0	17
	Distribution																
8	Land and Land Clearing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Conductors, Poles and Fittings	22,623	0	0	0	0	10,885	6,393	0	0	2,721	1,598	0	0	1,026	0	0
10	Transformers	5,350	0	0	0	0	0	0	3,852	1,498	0	0	0	0	0	0	0
11	Services	3,181	0	0	0	0	0	0	0	0	0	0	3,181	0	0	0	0
12	Meters	2,974	0	0	0	0	0	0	0	0	0	0	0	2,974	0	0	0
13	Street Lighting	2,502	0	0	0	0	0	0	0	0	0	0	0	0	2,502	0	0
	General Plant																
14	Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Buildings	1,351	83	70	202	111	226	133	71	28	56	33	67	18	44	207	1
16	Computer Equipment	6,186	266	226	695	402	817	480	257	100	204	120	243	66	159	2,146	4
17	Misc. Equipment	618	33	28	119	53	107	63	34	13	27	16	32	9	21	63	1
18	Transportation	3,356	56	48	459	377	766	450	241	94	192	113	228	62	150	117	3
19	Tele-communications	297	19	16	87	24	49	29	15	6	12	7	15	4	10	5	0
20	Total	71,291	5,267	3,526	9,862	7,521	12,851	7,547	4,470	1,738	3,213	1,887	3,766	3,133	3,912	2,538	60

FUNCTIONAL CLASSIFACTION OF DEPRECIATION EXPENSES (NET OF AMORTIZED CIAC)

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Common costs Classified based on the transmission common as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on Schedule 5.1 line 20 and classified as shown in Schedule 5.1 line 4.
5	Other Production	Functional splits on based Schedule 5.1 line 20 and classified as shown in Schedule 5.1 line 5.
6	Transmission	Functional splits based on Schedule 5.1 line 20 and common transmission costs classified as shown in Schedule 5.1 line 6.
7	Distribution	Functional splits based on Schedule 5.1 line 20 and distribution substation common costs classified as shown in Schedule 5.1 line 7.
8	Land and Land Clearing	Functional splits based on Schedule 5.1 line 21 and classified as shown in Schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on Schedule 5.1 line 22 and classified as shown in Schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in Schedule 5.1 line 14.
11	Services	Classified as shown in Schedule 5.1 line 15.
12	Meters	Classified as shown in Schedule 5.1 line 16.
13	Street Lighting	Classified as shown in Schedule 5.1 line 17.
	General Plant	
14	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
15	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	General Prop and Other Equip	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Total	Total of Lines 1 through 19.

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CUSTOMER STATISTICS

Line No.	Class of Service	Rate Class	BILLING INFORMATION: Number of Customers At Year End 2021	2022	Average	2022 Energy Sales kWh	2022 Total Billing Demands kW \ kVA	Non-coincident Maximum Class Demands (NCP): Estimated Class Load Factor	Class NCP Demand kW	Class Demand Coincident with System Peak (1CP): Estimated Class Load Factor	Class 1CP Demand kW
			A	B	C	D	E	F	G	H	I
	DOMESTIC										
1	Domestic Regular	1.1	63,664	62,883	63,274	591,644,000	0	43.0%	157,068	51.8%	130,385
2	Domestic All Electric	1.1	173,132	175,470	174,301	2,956,337,000	0	47.9%	704,554	46.8%	721,114
	GENERAL SERVICE										
3	(0-10 kW)	2.1	12,813	12,590	12,702	89,530,000	0	50.9%	20,079	65.2%	15,675
4	(10-100 kW)	2.1	10,223	10,479	10,351	691,867,000	2,639,541	52.6%	150,153	59.7%	132,295
	(110-350 kVA)	2.3									
5	Primary		15	14	15	10,180,003	28,598	56.7%	2,050	68.4%	1,699
6	Secondary		947	966	957	507,421,997	1,658,909	56.7%	102,160	68.4%	84,686
	(350-1000 kVA)	2.3									
7	Transmission		1	2	2	203,596	5,470	56.7%	41	68.4%	34
8	Primary		41	40	41	93,711,067	250,208	56.7%	18,867	68.4%	15,640
9	Secondary		220	236	228	423,089,337	1,181,533	56.7%	85,181	68.4%	70,611
	(1000 kVA and Over)	2.4									
10	Transmission		2	2	2	20,175,346	58,717	66.2%	3,479	74.4%	3,096
11	Primary		26	28	27	261,005,321	576,948	66.2%	45,008	74.4%	40,047
12	Secondary		28	29	29	111,387,334	344,778	66.2%	19,208	74.4%	17,091
13	**STREET LIGHTING**	4.1	10,942	11,025	10,984	17,400,026	0	48.0%	4,138	48.0%	4,138
14	Total		272,054	273,764	272,913	5,773,952,026	6,744,702	50.2%	1,311,986	53.3%	1,236,510

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ENERGY AND DEMAND LOSS FACTORS[1]
(Losses as a percentage of delivered)

Demand Loss Factors	
Transmission	1.2776%
Primary	3.7140%
Secondary	2.7695%
Energy Loss Factors	
Transmission	0.7948%
Primary	2.3689%
Secondary	2.1249%

(1) Based on a three year average (2020 to 2022)

DEVELOPMENT OF CUSTOMER COST ALLOCATORS

				Customer Related Costs			Primary Lines			Secondary Lines			Transformers			Service Drops			Meters		
Line No.	Class of Service	Rate Code	Average Number of Customers A	Weighting Factor B	Weighted Number of Customer C	Allocation Factors D	Weighting Factor E	Weighted Number of Customer F	Allocation Factors G	Weighting Factor H	Weighted Number of Customer I	Allocation Factors J	Weighting Factor K	Weighted Number of Customer L	Allocation Factors M	Weighting Factor N	Weighted Number of Customer O	Allocation Factors P	Weighting Factor Q	Weighted Number of Customer R	Allocation Factors S
	DOMESTIC																				
1	Domestic Regular	1.1	63,274	1.0	63,274	24.014%	1.0	63,274	23.185%	1.0	63,274	23.192%	1.0	63,274	22.118%	1.0	63,274	23.947%	1.0	63,274	16.796%
2	Domestic All Electric	1.1	174,301	1.0	174,301	66.152%	1.0	174,301	63.868%	1.0	174,301	63.887%	1.0	174,301	60.928%	1.0	174,301	65.966%	1.0	174,301	46.268%
	GENERAL SERVICE																				
3	(0-10 kW)	2.1	12,702	0.9	10,797	4.098%	1.0	12,702	4.654%	1.0	12,702	4.656%	1.2	15,242	5.328%	1.0	12,702	4.807%	2.6	33,025	8.767%
4	(10-100 kW)	2.1	10,351	0.9	9,523	3.614%	1.0	10,351	3.793%	1.0	10,351	3.794%	1.8	18,632	6.513%	1.2	12,421	4.701%	7.2	74,527	19.783%
	(110-350 kVA)	2.3																			
5	Primary		15	0.9	14	0.005%	1.0	15	0.005%	0.0	0	0.000%	0.0	0	0.000%	0.0	0	0.000%	91.2	1,368	0.363%
6	Secondary		957	0.9	880	0.334%	1.0	957	0.351%	1.0	957	0.351%	3.0	2,871	1.004%	1.6	1,531	0.579%	17.7	16,939	4.496%
	(350-1000 kVA)	2.3																			
7	Transmission		2	0.9	2	0.001%	0.0	0	0.000%	0.0	0	0.000%	0.0	0	0.000%	0.0	0	0.000%	166.0	332	0.088%
8	Primary		41	0.9	38	0.014%	1.0	41	0.015%	0.0	0	0.000%	0.0	0	0.000%	0.0	0	0.000%	91.2	3,739	0.993%
9	Secondary		228	0.9	210	0.080%	1.0	228	0.084%	1.0	228	0.084%	3.0	684	0.239%	0.0	0	0.000%	17.7	4,036	1.071%
	(1000 kVA and Over)	2.4																			
10	Transmission		2	0.9	2	0.001%	0.0	0	0.000%	0.0	0	0.000%	0.0	0	0.000%	0.0	0	0.000%	175.9	352	0.093%
11	Primary		27	0.9	25	0.009%	1.0	27	0.010%	0.0	0	0.000%	0.0	0	0.000%	0.0	0	0.000%	138.4	3,737	0.992%
12	Secondary		29	0.9	27	0.010%	1.0	29	0.011%	1.0	29	0.011%	3.0	87	0.030%	0.0	0	0.000%	37.5	1,088	0.289%
13	**STREET LIGHTING**	4.1	10,984	0.4	4,394	1.667%	1.0	10,984	4.025%	1.0	10,984	4.026%	1.0	10,984	3.840%	0.0	0	0.000%	0.0	0	0.000%
14	Total		272,913		263,485	100.0%		272,909	100.0%		272,826	100.0%		286,075	100.0%		264,229	100.0%		376,717	100.0%

NOTES:
Column
A - See Schedule 4.1, Column C.
B - Weighting Factors estimated based on general review of Customer accounting and Customer service activities.
C - Column A times B.
D - Class weighted number of customers divided by the total number of weighted customers for Column C.
E - Equal weighting assigned to all Customers supplied through primary lines.
F - Column A times E.
G - Class weighted number of customers divided by the total number of weighted customers for Column F.
H - Equal weighting assigned to all Customers supplied through secondary lines.
I - Column A times H.
J - Class weighted number of customers divided by the total number of weighted customers for Column I.
K - Weighting reflects customers with three phase supply having a weighting of three while those with single phase supply have a weighting of one.
L - Column A times K.
M - Class weighted number of customers divided by the total number of weighted customers for Column L.
N - Based on typical costs to provide Service Drops for customers within each class.
O - Column A times N.
P - Class weighted number of customers divided by the total number of weighted customers for Column O.
Q - Based on typical cost to provide metering for customers within each class.
R - Column A times Q.
S - Class weighted number of customers divided by the total number of weighted customers for Column R.

DEVELOPMENT OF ENERGY ALLOCATORS

			Secondary Energy Allocator				Primary Energy Allocator				Transmission Energy Allocator			
Line No.	Class of Service	Rate Code	Load at Meter kWh	Secondary Energy Loss Factor	Load at Secondary Input kWh	Secondary Allocation Factor	Load at Primary Output kWh	Primary Energy Loss Factor	Load at Primary Input kWh	Primary Allocation Factor	Load at Transmission Output kWh	Transmission Energy Loss Factor	Load at Transmission Input kWh	Transmission Allocation Factor
			A	B	C	D	E	F	G	H	I	J	K	L
	DOMESTIC													
1	Domestic Regular	1.1	591,644,000	0.021249	604,215,843	10.979%	604,215,843	0.023689	618,529,112	10.287%	618,529,112	0.007948	623,445,182	10.252%
2	Domestic All Electric	1.1	2,956,337,000	0.021249	3,019,156,205	54.862%	3,019,156,205	0.023689	3,090,676,996	51.403%	3,090,676,996	0.007948	3,115,241,697	51.226%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	89,530,000	0.021249	91,432,423	1.661%	91,432,423	0.023689	93,598,366	1.557%	93,598,366	0.007948	94,342,285	1.551%
4	(10-100 kW)	2.1	691,867,000	0.021249	706,568,482	12.839%	706,568,482	0.023689	723,306,383	12.030%	723,306,383	0.007948	729,055,222	11.988%
	(110-350 kVA)	2.3												
5	Primary		0	0.021249	0	0.000%	10,332,703	0.023689	10,577,474	0.176%	10,577,474	0.007948	10,661,544	0.175%
6	Secondary		507,421,997	0.021249	518,204,207	9.416%	518,204,207	0.023689	530,479,947	8.823%	530,479,947	0.007948	534,696,202	8.792%
	(350-1000 kVA)	2.3												
7	Transmission		0	0.021249	0	0.000%	0	0.023689	0	0.000%	206,650	0.007948	208,293	0.003%
8	Primary		0	0.021249	0	0.000%	95,116,733	0.023689	97,369,953	1.619%	97,369,953	0.007948	98,143,849	1.614%
9	Secondary		423,089,337	0.021249	432,079,562	7.851%	432,079,562	0.023689	442,315,095	7.356%	442,315,095	0.007948	445,830,616	7.331%
	(1000 kVA and Over)	2.4												
10	Transmission		0	0.021249	0	0.000%	0	0.023689	0	0.000%	20,477,976	0.007948	20,640,735	0.339%
11	Primary		0	0.021249	0	0.000%	264,920,401	0.023689	271,196,100	4.510%	271,196,100	0.007948	273,351,567	4.495%
12	Secondary		111,387,334	0.021249	113,754,203	2.067%	113,754,203	0.023689	116,448,926	1.937%	116,448,926	0.007948	117,374,462	1.930%
13	**STREET LIGHTING**	4.1	17,400,026	0.021249	17,769,759	0.323%	17,769,759	0.023689	18,190,707	0.303%	18,190,707	0.007948	18,335,287	0.302%
14	Total		5,388,676,694	0.021249	5,503,180,685	100.00%	5,873,550,521	0.023689	6,012,689,059	100.000%	6,033,373,685	0.007948	6,081,326,939	100.000%

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DEVELOPMENT OF ENERGY ALLOCATORS

NOTES:

A - See Schedule 4.1, Column D, Excluding Primary and Transmission Customers.
B - See Schedule 4.2.
C - Estimated Load at Secondary Input including losses. It is equal to Column A times (one plus the loss factor from Column B).
D - Class load relative to the Total Load for Column C.
E - Equal to Column C and includes customers that are supplied at primary level as shown in Schedule 4.1. Energy Sales increased by 1.5% due to reported demand sales being based at secondary sales levels.
F - See Schedule 4.2.
G - Estimated Load at Primary Input including losses. It is equal to Column E times (one plus the loss factor from Column F).
H - Class load relative to the Total Load for Column G.
I - Equal to Column G but includes customers that are supplied at transmission level as shown in Schedule 4.1. Energy Sales increased by 1.5% due to reported energy sales been based at secondary sales levels.
J - See Schedule 4.2.
K - Estimated Load at Transmission Input including losses. It is equal to Column I times (one plus the loss factor from Column J).
L - Class load relative to the Total Load for Column K.

DEVELOPMENT OF NON-COINCIDENT PEAK (NCP) DEMAND ALLOCATORS

Line No.	Class of Service	Rate Code	Load at Meter kW A	Secondary Demand Allocator: Secondary Demand Loss Factor B	Load at Secondary Input kW C	Secondary Allocation Factor D	Primary Demand Allocator: Load at Primary Output kW E	Primary Demand Loss Factor F	Load at Primary Input kW G	Primary Allocation Factor H	Transmission Demand Allocator: Load at Transmission Output kW I	Transmission Demand Loss Factor J	Load at Transmission Input kW K	Transmission Allocation Factor L
	DOMESTIC													
1	Domestic Regular	1.1	157,068	0.027695	161,418	12.641%	161,418	0.03714	167,413	12.011%	167,413	0.012776	169,552	11.981%
2	Domestic All Electric	1.1	704,554	0.027695	724,067	56.703%	724,067	0.03714	750,959	53.879%	750,959	0.012776	760,553	53.742%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	20,079	0.027695	20,635	1.616%	20,635	0.03714	21,402	1.536%	21,402	0.012776	21,675	1.532%
4	(10-100 kW)	2.1	150,153	0.027695	154,311	12.084%	154,311	0.03714	160,042	11.483%	160,042	0.012776	162,087	11.453%
	(110-350 kVA)	2.3												
5	Primary		0	0.027695	0	0.000%	2,080	0.03714	2,158	0.155%	2,158	0.012776	2,185	0.154%
6	Secondary		102,160	0.027695	104,990	8.222%	104,990	0.03714	108,889	7.813%	108,889	0.012776	110,280	7.793%
	(350-1000 kVA)	2.3												
7	Transmission		0	0.027695	0	0.000%	0	0.03714	0	0.000%	42	0.012776	42	0.003%
8	Primary		0	0.027695	0	0.000%	19,150	0.03714	19,861	1.425%	19,861	0.012776	20,115	1.421%
9	Secondary		85,181	0.027695	87,541	6.855%	87,541	0.03714	90,792	6.514%	90,792	0.012776	91,952	6.497%
	(1000 kVA and Over)	2.4												
10	Transmission		0	0.027695	0	0.000%	0	0.03714	0	0.000%	3,531	0.012776	3,576	0.253%
11	Primary		0	0.027695	0	0.000%	45,683	0.03714	47,380	3.399%	47,380	0.012776	47,985	3.391%
12	Secondary		19,208	0.027695	19,740	1.546%	19,740	0.03714	20,473	1.469%	20,473	0.012776	20,734	1.465%
13	**STREET LIGHTING**	4.1	4,138	0.027695	4,253	0.333%	4,253	0.03714	4,411	0.316%	4,411	0.012776	4,467	0.316%
14	Total		1,242,541	0.027695	1,276,954	100.00%	1,343,867	0.03714	1,393,778	100.000%	1,397,351	0.012776	1,415,203	100.000%

DEVELOPMENT OF NON-COINCIDENT PEAK (NCP) DEMAND ALLOCATORS

NOTES:

A - See Schedule 4.1, Class NCP Demand, Excluding Primary and Transmission Customers.
B - See Schedule 4.2.
C - Estimated Load at Secondary Input including losses. It is equal to Column A times (one plus the loss factor from Column B).
D - Class load relative to the Total Load for Column C.
E - Equal to Column C but includes customers that are supplied at primary level as shown in Schedule 4.1. Class NCP Demand increased by 1.5% due to reported demand sales being based at secondary sales levels.
F - See Schedule 4.2.
G - Estimated Load at Primary Input including losses. It is equal to Column E times (one plus the loss factor from Column F).
H - Class load relative to the Total Load for Column G.
I - Equal to Column G but includes customers supplied at transmission level as shown in Schedule 4.1. Class NCP Demand increased by 1.5% due to reported demand sales been based at secondary sales levels.
J - See Schedule 4.2.
K - Estimated Load at Transmission Input including losses. It is equal to Column I times (one plus the loss factor from Column J).
L - Class load relative to the Total Load for Column K.

DEVELOPMENT OF SINGLE COINCIDENT PEAK (1CP) DEMAND ALLOCATORS

Line No.	Class of Service	Rate Code	Secondary Demand Allocator				Primary Demand Allocator				Transmission Demand Allocator			
			Load at Meter kW	Secondary Demand Loss Factor	Load at Secondary Input kW	Secondary Allocation Factor	Load at Primary Output kW	Primary Demand Loss Factor	Load at Primary Input kW	Primary Allocation Factor	Load at Transmission Output kW	Transmission Demand Loss Factor	Load at Transmission Input kW	Transmission Allocation Factor
			A	B	C	D	E	F	G	H	I	J	K	L
	DOMESTIC													
1	Domestic Regular	1.1	130,385	0.027695	133,996	11.087%	133,996	0.03714	138,972	10.577%	138,972	0.012776	140,748	10.552%
2	Domestic All Electric	1.1	721,114	0.027695	741,085	61.320%	741,085	0.03714	768,609	58.500%	768,609	0.012776	778,429	58.359%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	15,675	0.027695	16,109	1.333%	16,109	0.03714	16,708	1.272%	16,708	0.012776	16,921	1.269%
4	(10-100 kW)	2.1	132,295	0.027695	135,959	11.250%	135,959	0.03714	141,009	10.732%	141,009	0.012776	142,810	10.707%
	(110-350 kVA)	2.3												
5	Primary		0	0.027695	0	0.000%	1,724	0.03714	1,789	0.136%	1,789	0.012776	1,811	0.136%
6	Secondary		84,686	0.027695	87,031	7.201%	87,031	0.03714	90,263	6.870%	90,263	0.012776	91,416	6.854%
	(350-1000 kVA)	2.3												
7	Transmission		0	0.027695	0	0.000%	0	0.03714	0	0.000%	34	0.012776	35	0.003%
8	Primary		0	0.027695	0	0.000%	15,874	0.03714	16,464	1.253%	16,464	0.012776	16,674	1.250%
9	Secondary		70,611	0.027695	72,566	6.004%	72,566	0.03714	75,262	5.728%	75,262	0.012776	76,223	5.714%
	(1000 kVA and Over)	2.4												
10	Transmission		0	0.027695	0	0.000%	0	0.03714	0	0.000%	3,142	0.012776	3,182	0.239%
11	Primary		0	0.027695	0	0.000%	40,648	0.03714	42,158	3.209%	42,158	0.012776	42,696	3.201%
12	Secondary		17,091	0.027695	17,564	1.453%	17,564	0.03714	18,216	1.386%	18,216	0.012776	18,449	1.383%
13	**STREET LIGHTING**	4.1	4,138	0.027695	4,253	0.352%	4,253	0.03714	4,411	0.336%	4,411	0.012776	4,467	0.335%
14	Total		1,175,995	0.027695	1,208,564	100.00%	1,266,810	0.03714	1,313,860	100.000%	1,317,036	0.012776	1,333,863	100.000%

DEVELOPMENT OF SINGLE COINCIDENT PEAK (1CP) DEMAND ALLOCATORS

NOTES:

A - See Schedule 4.1, Class 1CP Demand.
B - See Schedule 4.2.
C - Estimated Load at Secondary Input including losses. It is equal to Column A times (one plus the loss factor from Column B).
D - Class load relative to the Total Load for Column C.
E - Equal to Column C but includes customers that are supplied at primary level as shown in Schedule 4.1. Class 1CP Demand increased
- by 1.5% due to reported demand sales being based at secondary sales levels.
F - See Schedule 4.2.
G - Estimated Load at Primary Input including losses. It is equal to Columns E times (one plus the loss factor from Column F).
H - Class load relative to the Total Load for Column G.
I - Equal to Column G but includes customers that are supplied at transmission level as shown in Schedule 4.1. Class 1CP Demand increased
- by 1.5% due to reported demand sales been based at secondary sales levels.
J - See Schedule 4.2.
K - Estimated Load at Transmission Input including losses. It is equal to Columns I times (one plus the loss factor from Column J).
L - Class load relative to the Total Load for Column K.

FUNCTIONAL CLASSIFICATION SPLITS

Scenarios

Line No.	Utility Plant Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Substation Demand E	Distribution Primary Demand F	Distribution Primary Customer G	Distribution Transformers Demand H	Distribution Transformers Customer I	Distribution Secondary Demand J	Distribution Secondary Customer K	Services Customer L	Meters Customer M	St. Lighting Customer N
	PURCHASED POWER														
1	Purchased from Nfld. & Lab. Hydro - Production	100.0%	34.2%	65.8%											
2	Purchased from Nfld. & Lab. Hydro - Transmission	100.0%	100.0%	0.0%											
3	Purchased from Deer Lake Power - Secondary	100.0%	34.2%	65.8%											
	PRODUCTION														
4	Hydro	100.0%	45.7%	54.3%											
5	Other Production	100.0%	100.0%												
	TRANSMISSION														
6	Common	100.0%			100.0%										
	DISTRIBUTION														
7	Substations - Common	100.0%				100.0%									
	Land and Land Use														
8	Primary	100.0%					63.0%	37.0%							
9	Secondary	100.0%									63.0%	37.0%			
10	Street Lighting	100.0%													100.0%
	Conductors, Poles and Fixtures														
11	Primary	100.0%					63.0%	37.0%							
12	Secondary	100.0%									63.0%	37.0%			
13	Street Lighting	100.0%													100.0%
14	Transformers	100.0%							72.0%	28.0%					
15	Services	100.0%											100.0%		
16	Meters	100.0%												100.0%	
17	Street Lights	100.0%													100.0%

MISCELLANEOUS FUNCTIONAL COST ASSIGNMENT FACTORS

Line No.	Cost Item	Total	Production	Transmission
18	Purchased from Nfld. & Labrador Hydro	100.0%	87.8%	12.2%

Line No.		Total	Common	Specifically Assigned
19	Transmission	100.0%	99.56%	0.44%

Line No.		Total	Hydro Production	Other Production	Total Production	Transmission Common	Transmission Specifically Assigned	Distribution Substation Common	Distribution Specifically Assigned	Cust. Acc. Cust. Serv.
20	Substations	100.0%	3.71%	0.70%	4.41%	27.72%	0.09%	67.61%	0.18%	0.00%

Line No.	Distribution	Distribution Depreciation, Fixed Assets & CIACs Total	Primary	Secondary	St. Lighting	Distribution Acc. Depreciation Total	Primary	Secondary	St. Lighting
21	Land and Land Use	100.0%	76.37%	19.09%	4.53%	100.0%	76.30%	19.08%	4.62%
22	Conductors, Poles and Fixtures	100.0%	76.37%	19.09%	4.53%	100.0%	76.30%	19.08%	4.62%

Line No.	General Plant Related Costs		Production	Transmission	Distribution	Cust. Acc. Cust. Serv.
23	Gen. Prop. Land and Land Rights	100.0%	11.39%	14.49%	56.21%	17.91%
24	Gen. Prop. Buildings and Structures	100.0%	11.35%	15.02%	58.34%	15.29%
25	Computer Hardware and Software	100.0%	7.95%	11.28%	46.07%	34.70%
26	Gen. Prop. Other Equipment	100.0%	9.88%	19.34%	60.61%	10.17%
27	Transportation	100.0%	3.11%	13.74%	79.66%	3.49%
28	Communication - Total	100.0%	11.52%	29.26%	57.61%	1.61%
29	Communication - Scada	100.0%	11.52%	16.07%	72.41%	0.00%
30	Communication - Total Expenses	100.0%	5.75%	14.46%	64.52%	15.27%
31	Inventory	100.0%	5.12%	40.60%	54.28%	0.00%

FUNCTIONAL CLASSIFICATION SPLITS

Line No.	Utility Plant Category	Reason for Functional Classification.
1	Purchased Power from Nfld. & Lab. Hydro - Production	Classified based on the results, before deficit allocation, of NLH's 2019 test year COS. See NLH's July 11, 2019 Compliance Filing for Rate Setting, Exhibit 14, Schedule 3.2 A.
2	Purchased from Nfld. & Lab. Hydro - Transmission	Classified 100% to Demand.
3	Purchased from Deer Lake Power - Secondary	Assumed same classification as Nfld. and Lab. Hydro Production related purchased power allocated to Newfoundland Power.
	PRODUCTION	
4	Hydro	Classified based on Island Interconnected System load factor from NLH's 2019 test year COS. See NLH's July 11, 2019 Compliance Filing for Rate Setting, Exhibit 14 Schedule 4.2.
5	Other Production	Classified 100% to Demand.
	TRANSMISSION	
6	Common	Classified 100% to Demand.
	DISTRIBUTION	
7	Substation - Common	Classified 100% to Demand.
	Land and Land Use	
8	Primary	Classified between Demand and Customer Based on a minimum system analysis.
9	Secondary	Classified between Demand and Customer Based on a minimum system analysis.
10	Street Lighting	Classified 100% to direct Street Lighting costs.
	Conductors, Poles and Fixtures	
11	Primary	Classified between Demand and Customer Based on a minimum system analysis.
12	Secondary	Classified between Demand and Customer Based on a minimum system analysis.
13	Street Lighting	Classified 100% to direct Street Lighting costs.
14	Transformers	Classified between Demand and Customer Based on a zero intercept method.
15	Services	Classified 100% to Customer.
16	Meters	Classified 100% to Customer.
17	Street Lights	Classified 100% to Direct Street Lighting.

MISCELLANEOUS FUNCTIONAL COST ASSIGNMENT FACTORS

Line No.	Utility Plant Category	Reason for Functional Classification.
18	Purchased from Nfld. & Labrador Hydro	Split between production and transmission related purchased power based on results ,before deficit allocation of Nfld. & Lab. Hydro 2019 Test Year Cost of Service. See NLH's July 11,2019 Compliance Filing for Rate Setting, Schedule 3.2A.
19	Transmission	Based on an analysis of 2022 year end fixed plant. Specifically Assigned based on 2022 Data.
20	Substations	Based on an analysis of 2022 year end fixed plant. Specifically Assigned based on 2022 Data.
	Distribution	
21	Land and Land Use	Split between the different functional groups are based on the split for Conductors Poles and Fittings.
22	Conductors, Poles and Fixtures	Functional split based on a study of fixed assets.
23	Gen. Prop. Land and Land Rights	Based on a 2019 General Property Fixed Plant Allocation Study (2019 Data).
24	Gen. Prop. Buildings and Structures	Based on a 2019 General Property Fixed Plant Allocation Study (2019 Data).
25	Computer Hardware and Software	Based on a 2019 General Property Fixed Plant Allocation Study (2019 Data).
26	Gen. Prop. Other Equipment	Based on a 2019 General Property Fixed Plant Allocation Study (2019 Data).
27	Transportation	Based on a 2019 General Property Fixed Plant Allocation Study (2019 Data).
28	Communication - Total	Based on a 2019 General Property Fixed Plant Allocation Study (2019 Data).
29	Communication - Scada	Based on a 2019 General Property Fixed Plant Allocation Study (2019 Data).
30	Communication - Total Expenses	Based on a 2019 General Property Fixed Plant Allocation Study (2019 Data).
31	Inventory	Based on an allocation of the year end inventory for 2022.

Newfoundland Power Inc.
2022 Pro Forma Cost of Service Study

RECONCILIATION OF EXPENSES WITH ANNUAL REPORT TO BOARD
(All dollars are times $1,000)

The total expenses shown on Schedule 1.1, reflects adjustment of the total reported expenses to *include* depreciation, the amortization of the various Deferrals and *exclude* non-regulated expense, Rural Deficit and certain expenses associated recovered through other revenue (expense credits). Also, Curtailable Service Option credit payments are included as an expense in the Cost of Service Study as opposed to a reduction to class revenue from rates as recorded by the Company.

Total Reported Company Expenses	$566,108	(Return 20)
Add		
Depreciation Expense	70,662	(Return 6)
Curtailable Credits	396	(2022 Curtailable Service Option Report)
2022 Cost Deferral less 2022 Amortization	(656)	(Schedule 3.2, page 1 of 2 line 28)
Pension and OPEBs Variance Deferral	832	(Schedule 3.2, page 1 of 2 line 29)
Less		
Deduct non-regulated expenses	3,234	(Non regulated Expenses from Return 13 plus tax adjustment from Schedule 5.4)
Other Contract Expenses	6,826	Return 20, line 29
Pro Forma Adjustment - Area Lighting		
Purchase Power Expense	(919)	From detail analysis of all LED fixtures at January 1, 2022
O&M Expense	29	From detail analysis of all LED fixtures at January 1, 2022
Depreciation Expense	628	From detail analysis of all LED fixtures at January 1, 2022
Total Proforma Adjustments	(262)	
Rural Deficit	61,763	(Schedule 1.1, page 2 of 2)
Expense Credits		
Wheeling Revenues	765	(Schedule 1.1, page 1 of 2)
Joint Use Revenues	2,483	(Schedule 1.1, page 1 of 2)
Revenue from Temp. Services and Reconnects	62	(Schedule 1.1, page 1 of 2)
Customer Service Fees	257	(Schedule 1.1, page 1 of 2)
RSA Transfer - Energy Supply Cost Variance	3,814	(Schedule 1.1, page 1 of 2)
RSA Transfer - CDM Revenue Deferral	3,709	(Schedule 1.1, page 1 of 2)
Total Expense Credits	11,090	
Rounding	1	
Total expense before Return and Taxes on Schedule 1.1 Excluding RSA, MTA and the Hydro Rural deficit	$554,168	

Newfoundland Power Inc.
2022 Pro Forma Cost of Service Study

RECONCILIATION OF REVENUE WITH ANNUAL REPORT TO BOARD
(All dollars are times 1,000)

Revenue from Rates shown on Schedule 1.4 does not include customer billings associated with the RSA and MTA rate adjustments. Also the Curtailable Service Option credit payments are included as an expense in the Cost of Service Study as opposed to a reduction to class revenue from rates as recorded by the Company. As a result revenue is increased to remove the impact of the Curtailable Service Option credit payments on revenue.

Revenue from Rates	$715,444	(Return 14)
Pro Forma Adjustments		
January & February at March 1, 2022 Rates	(1,845)	From 2023 Test Year
Less Revenue due to LED fixtures replacing HPS fixtures	(1,254)	From detail analysis of all LED fixtures at January 1, 2022
Required Rate Change to meet 8.36% RORB	4,423	From detail analysis of all LED fixtures at January 1, 2022
Total Pro Forma Adjustments	1,324	
Add		
RSA Billings	68,133	(Schedule 1.4)
MTA Billings	19,413	(Schedule 1.4)
Curtailable Service Option Credits	396	(2022 Curtailable Service Option Report)
Rounding	(1)	
Total Revenue from Final Rates	$804,709	(Schedule 1.4)

Newfoundland Power Inc.
2022 Pro Forma Cost of Service Study

RECONCILIATION OF RETURN AND TAXES WITH ANNUAL REPORT TO BOARD
(All dollars are times 1,000)

Return and Taxes From Annual Report to Board		
Return on Rate Base (After adjustment to Regulated Earnings)	$82,681	(Return 13)
Total Income Tax	11,002	(Return 22)
Total Pro Forma Revenue Adjustments	1,324	Schedule 5.3
Less Total Pro Forma Expense Adjustments	(262)	Schedule 5.2
Total Pro Forma Adjustment	1,586	
Total Return and Taxes	95,269	
Adjustments		
Tax Adjustment for non-regulated expenses[1].	970	
Tax adjustment for Part VI.1 Taxes	-	(Return 12)
Tax Adjustment for Cost of Removal[2]	7,525	(Return 6, note 2)
Equity component of AFUDC	674	(Return 13 and Return 25)
Other Adjustments		
Interest on Tax	-	(Return 25)
Interest on security deposits	23	(Return 25)
Rounding	-	
Adjusted Return and Taxes	104,461	(Schedule 1.1)

Notes:

1 - Tax adjustment associated with non-regulated expenses from detail.

Non-regulated expenses	3,234	
Income taxes (Tax Rate 30%)	970	
Rounding	-	
Non-regulated expenses net of taxes	2,264	(Return 12)

2 - The income tax is adjusted to reflect cost of removal recorded net of taxes for regulatory purposes while the tax impact of the cost of removal is recorded as part of Total Income Tax on Return 22.

Customer Rate Impacts

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1.0 Introduction

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") performed an impact analysis on the proposed rates with effect on July 1, 2025 relative to the rates with effect on July 1, 2024[1] for the Domestic class and for each of the General Service classes.

This report summarizes the results of this analysis.

2.0 Domestic Methodology

2.1 General

There were approximately 237,054 customer accounts billed on the Domestic rate and approximately 1,299 customer accounts billed on the Domestic - Seasonal Optional rate at December 31, 2022. Evaluation of customer impacts of the proposed rate change for the Domestic class was based upon data from a representative sample of customers served under the Domestic rate.

The Domestic rate has the same energy price year-round. Therefore, the billing impacts can be determined based upon annual usage. The sample design methodology focused on ensuring that the annual usage distribution of the sample is reasonably representative of the annual usage of the population.

The Domestic customers identified in the Customer Service System with electricity as their primary heating source ("Domestic All-Electric") were analyzed separately from the Domestic customers identified as having some other heating source ("Domestic Regular"). The billing impacts were determined by applying the proposed rates with effect on July 1, 2024 and July 1, 2025 to the 2022 monthly electricity usage of a sample of 5,770 customers in the Domestic Regular subgroup and 15,485 in the Domestic All-Electric subgroup.[2]

The Domestic samples were selected using a systematic random sampling method to ensure the samples had comparable annual energy usage distributions to the subgroup populations.

The Domestic - Seasonal Optional Rate has approximately 1,299 participants. The impacts of the proposed customer rates were analyzed based upon the usage data of all customers on the rate option for the full year of 2022.

1 Reflects the customer rates proposed in the *2024 Rate of Return on Rate Base Application* filed with the Board on November 23, 2023, with effect on July 1, 2024.

2 The samples represent approximately 11% of the customers in the respective subgroups who were active for all 12 months of 2022.

2.2 Sample Reliability

The Domestic samples provide a 95% confidence with ±0.8% relative accuracy on average monthly energy usage for the Domestic All-Electric subgroup and a 95% confidence with ±1.9% relative accuracy on average monthly energy usage for the Domestic Regular subgroup.

The Domestic samples are reasonable for the purpose of evaluating the effects of the proposed rate changes on customer accounts.

3.0 General Service Methodology

There were 24,386 General Service customer accounts billed at year-end 2022.

Table 1 provides the breakdown of General Service customer accounts, sales and revenue by rate class.

Table 1:
General Service Classes

Rate	Rate Class	Customer Accounts	Sales (GWh)	Revenue ($000s)
#2.1	0-100 kW (110 kVA)	23,069	781.3	95,983
#2.3	110-1000 kVA	1,258	1,034.6	107,955
#2.4	1000 kVA and Over	59	392.6	36,923
	Total General Service	**24,386**	**2,208.5**	**240,861**

The Company reviewed the billing impacts for all customer accounts that were on each General Service rate for the full year of 2022.

4.0 Customer Impacts

4.1 Domestic

The overall average revenue increase of 5.5% applies to Domestic Rate #1.1 and Domestic Seasonal Rate #1.1S customers. The proposed 5.5% increase has been applied to Rate #1.1 energy charges. Slightly higher and lower rate increases have been applied to rate components that require the maintenance of specific cost differentials. This includes basic customer charges as well as winter and non-winter energy charges for Rate #1.1S customers.[3]

[3] See *Volume 1, Application, Company Evidence and Exhibits, Section 5.4.3 Changes to Rate Components*.

Table 2 shows the customer bill impacts for Rate #1.1 and #1.1S under the proposed rate.

Table 2:
Domestic #1.1 and #1.1S
Customer Bill Impacts

Annual Impact (%)	Percentage of Customers
Less than 5.4	0.3
5.4 to 5.6	91.4
Greater than 5.6	8.3
Total	**100.0**

Approximately 91.4% of Rate #1.1 and #1.1S customers will receive annual bill impacts of between 5.4% and 5.6%.

Approximately 8.3% of domestic customers will receive annual bill impacts of between 5.7% and 6.0%. These customers typically have 200-amp service and have lower than average energy consumption.

4.2 General Service

The overall average revenue increase of 5.5% applies to General Service Rate #2.1. The proposed 5.5% increase has been applied to Rate #2.1 energy charges. Slightly higher and lower rate increases have been applied to rate components that require the maintenance of specific cost differentials. This applies to basic customer charges for unmetered, single phase, and three phase customers. It also applies to winter and non-winter demand charges.[4]

Table 3 shows the customer bill impacts for Rate #2.1 under the proposed rate.

Table 3:
Rate #2.1
Customer Bill Impacts

Annual Impact (%)	Percentage of Customers
4.2 to 5.2	5.6
5.3 to 5.7	62.9
5.8 to 6.6	28.3
6.7 to 11.0	3.2
Total	**100.0**

4 See *Volume 1, Application, Company Evidence and Exhibits, Section 5.4.3 Changes to Rate Components*.

Approximately 5.6% of Rate #2.1 customers will receive annual bill impacts of between 4.2% and 5.2%. Approximately 91.2% of Rate #2.1 customers will receive annual bill impacts of between 5.3% and 6.6%. Approximately 3.2% of Rate #2.1 customers will receive annual bill impacts of between 6.7% and 11.0%.

Customers receiving annual bill impacts of greater than 6.6% are unmetered customers with low energy usage.

The overall average revenue increase of 5.5% applies to General Service Rate #2.3 customers. The proposed 5.4% increase has been applied to Rate #2.3 energy charges and the basic customer charge. A slightly higher rate increase has been applied to non-winter demand charges and a slightly lower rate increase has been applied to winter demand charges. This is to maintain the specific cost differential between the winter and non-winter demand charges for Rate #2.3 customers.[5]

Table 4 shows the customer bill impacts for Rate #2.3 under the proposed rate.

Table 4:
Rate #2.3
Customer Bill Impacts

Annual Impact (%)	Percentage of Customers
5.2 to 5.6	98.5
5.7 to 6.0	1.5
Total	**100.0**

Approximately 98.5% of Rate #2.3 customers will receive annual bill impacts of 5.2% to 5.6%. Approximately 1.5% of Rate #2.3 customers will receive annual bill impacts of 5.7% to 6.0%.

Customers receiving annual bill impacts of 5.7% to 6.0% experienced relatively low demand in the 2022 winter months compared to the non-winter months.

The overall average revenue increase of 5.5% applies to Rate #2.4 customers. The proposed 5.3% increase has been applied to Rate #2.4 energy charges and the basic customer charge. Winter and non-winter demand charges differ slightly from the proposed 5.3% increase to maintain specific cost differentials for those rate components.[6]

[5] See *Volume 1, Application, Company Evidence and Exhibits, Section 5.4.3 Changes to Rate Components*.
[6] See *Volume 1, Application, Company Evidence and Exhibits, Section 5.4.3 Changes to Rate Components*.

Table 5 shows the customer bill impacts for Rate #2.4 under the proposed rate.

Table 5:
Rate #2.4
Customer Bill Impacts

Annual Impact (%)	**Percentage of Customers**
5.2 to 5.5	94.6
5.6 to 5.8	5.4
Total	**100.0**

Approximately 94.6% of Rate #2.4 customers will receive annual bill impacts of 5.2% to 5.5%. Approximately 5.4% of Rate #2.4 customers will receive annual bill impacts of 5.6% to 5.8%.

Differences in annual rate impacts are the result of customers' monthly billing demand and the changes to winter and non-winter demand charges required to maintain specific cost differentials between those rate components.

REPORT:

COST OF CAPITAL

PREPARED FOR:

NEWFOUNDLAND POWER INC.

BEFORE THE:

NEWFOUNDLAND AND LABRADOR BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

NOVEMBER 7, 2023

www.ceadvisors.com

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I. INTRODUCTION AND QUALIFICATIONS

A. James Coyne

My name is James M. Coyne, and I am employed by Concentric Energy Advisors, Inc. ("Concentric") as a Senior Vice President. My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752. I am testifying on behalf of Newfoundland Power Inc. ("Newfoundland Power" or the "Company").

I am among Concentric's professionals who provide expert testimony before federal, state, and Canadian provincial agencies on matters pertaining to economics, finance, and public policy in the energy industry. Concentric provides financial, economic, and regulatory advisory services to clients across North America, including utility companies, regulatory and public agencies, and utility sector investors. I regularly advise utilities, generating companies, public agencies and private equity investors on business issues pertaining to the utilities industry. This work includes calculating the cost of capital for the purpose of ratemaking, and providing expert testimony and studies on matters pertaining to incentive regulation, rate policy, valuation, capital costs, fuels and power markets. I have testified or provided expert evidence in state, provincial and federal jurisdictions across Canada and the U.S., including before the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board"). This work has been provided on behalf of utilities, regulatory commissions, and staff.

I am also a frequent speaker and author of articles and white papers on the energy industry. For example, on behalf of the Canadian Gas Association and the Canadian Electricity Association, I prepared a discussion paper for utility executives and provincial regulators that examined the roles that Canada's utilities and regulators can play to promote innovation. In addition, I facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white papers to facilitate further discussion on emerging industry issues. I have been an invited speaker for several CAMPUT events, including the Energy Regulation Course at Queen's University where I spoke on "Innovations in Utility Business Models and Regulation."

In earlier positions, I served as Senior Economist for the Massachusetts Energy Facilities Siting Council, where I analyzed the supply plans and facilities proposals from the state's electric and gas utilities, and I also served as State Energy Economist for the Maine Office of Energy Resources.

I hold a B.S. in Business Administration from Georgetown University and a M.S. in Resource Economics from the University of New Hampshire. My qualifications are detailed more fully in Attachment 1.

B. John Trogonoski

My name is John P. Trogonoski, and I am employed by Concentric as an Assistant Vice President. My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752. I am also testifying on behalf of Newfoundland Power.

I provide expert testimony before U.S. state and Canadian provincial regulatory agencies on matters pertaining to finance, economics, and public policy in the utility industry. I have testified or provided expert evidence on more than 25 occasions in various U.S. state and Canadian provincial jurisdictions. This testimony has been filed on behalf of both utilities and regulatory commission staff.

Prior to joining Concentric, I was a member of the Staff of the Colorado Public Utilities Commission from 1999-2008, where I supervised the financial analysts in the energy and telecommunications sections, provided advisory services to the Commissioners on financial and economic matters, and filed expert testimony on rate of return, revenue requirement, cost allocation, rate design, incentive regulation, and public policy matters. I hold a M.S. in Business Administration and a B.S. in Marketing from the University of Colorado at Denver. My qualifications are detailed more fully in Attachment 2.

C. Executive Summary

Concentric has been asked to estimate the cost of capital for Newfoundland Power for the purpose of establishing the return on equity ("ROE") and capital structure for rate-making purposes. In order to estimate the cost of capital, we have relied upon analytical tools and data sources normally used for such purposes before regulators in Canada and the U.S. We have also reviewed past decisions of the Board in consideration of such matters. The analysis provided in this report supports our overall recommendation on the cost of equity and capital structure for Newfoundland Power. That analysis includes the following:

- examination of the legal and regulatory requirements for determination of a fair rate of return;

- selection of Canadian, U.S. and North American proxy groups with companies comparable to Newfoundland Power with respect to business and financial risks;
- estimation of the cost of common equity for the proxy group companies using the Discounted Cash Flow ("DCF") method, the Capital Asset Pricing Model ("CAPM"), and the Bond Yield Plus Risk Premium ("Risk Premium") approach;
- examination of authorized returns on equity for other investor-owned electric utilities in Canada and the U.S.;
- development of a range of results for the Canadian, U.S. and North American proxy groups; and
- an assessment of the appropriateness of Newfoundland Power's capital structure based on an examination of the Company's business and financial risks relative to the respective proxy groups.

As shown in Figure 1 below, the ROE estimation models produce a range of results for the proxy group companies from 9.38 percent to 10.68 percent. The average of all methods for the North American Electric proxy group is just over 10.0 percent. Because the utilities in the North American Electric proxy group are most representative of Newfoundland Power, we place greater weight on those results.

Figure 1: Summary of Results[1]

	CANADIAN UTILITY PROXY GROUP	U.S. ELECTRIC PROXY GROUP	NORTH AMERICAN ELECTRIC PROXY GROUP
CONSTANT GROWTH DCF	10.03%	10.44%	10.07%
MULTI-STAGE DCF	10.17%	9.38%	9.42%
AVERAGE CAPM	10.09%	10.68%	10.37%
RISK PREMIUM		10.26%	10.26%
AVERAGE	**10.10%**	**10.19%**	**10.03%**

[1] DCF results are based on 90-day average stock prices for proxy group companies. Results include 50 basis points for flotation costs and financial flexibility except for risk premium results.

We also present our results using only the Multi-Stage DCF model, the CAPM with a historical market risk premium, and the Risk Premium model. This provides a more conservative estimate of the cost of equity for Newfoundland Power. Those results are summarized in Figure 2 below.

Figure 2: Summary of Alternative Results

	CANADIAN UTILITY PROXY GROUP	U.S. ELECTRIC PROXY GROUP	NORTH AMERICAN ELECTRIC PROXY GROUP
MULTI-STAGE DCF	10.17%	9.38%	9.42%
HISTORICAL CAPM	9.57%	10.15%	9.86%
RISK PREMIUM		10.26%	10.26%
AVERAGE	**9.87%**	**9.93%**	**9.85%**

The average results of the Multi-Stage DCF, historical CAPM and Risk Premium methods for the North American Electric proxy group is 9.85 percent, within the range from 9.42 percent to 10.26 percent. The average for the Canadian proxy group is 9.87 percent and for the U.S. Electric proxy group is 9.93 percent. Based on this analysis, we recommend Newfoundland Power's cost of equity be set at 9.85 percent. In addition, a common equity ratio of 45.0 percent remains reasonable, if not conservative, given the business and financial risks of Newfoundland Power.

D. Report Organization

The remainder of the report is organized as follows: Section II discusses the legal requirements and regulatory precedents for the determination of a fair rate of return; Section III provides an overview of economic and financial market conditions in Canada and the U.S. and how those conditions affect the cost of equity for Newfoundland Power. Section IV describes the selection of proxy group companies to estimate the cost of equity for Newfoundland Power and discusses the precedent in Canada for considering the use of U.S. data. Section V discusses the methods used to estimate the cost of equity and summarizes the results of the DCF, CAPM and Risk Premium analyses. Section VI provides an assessment of a reasonable capital structure for Newfoundland Power given the business and financial risks the Company faces. Section VII addresses the use of an automatic adjustment formula for future ROE determinations, and Section VIII summarizes our overall conclusions and recommendations.

II. LEGAL REQUIREMENTS AND KEY REGULATORY PRECEDENTS

A. The Fair Return Standard

The principles surrounding the concept of a "fair return" for a regulated company were first established by the Supreme Court of Canada in *Northwestern Utilities v. City of Edmonton* (1929) S.C.R. 186 ("Northwestern"), where the Supreme Court of Canada found:

> *By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.*[2]

United States common law regarding a fair return for utility cost of capital has evolved similarly. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)), the U.S. Supreme Court stated:

> *The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.*

The U.S. Supreme Court further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591, 603 (1944)), when it described the relevant criteria as follows:

> *From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.*

With the passage of time, the Fair Return Standard has been interpreted many times in both Canada and the U.S. For example, the National Energy Board (now the Canadian Energy

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2 Northwestern, at 193.

Regulator) summarized its interpretation of the "fair return standard" in its RH-2-2004 Phase II Decision and more recently reiterated that interpretation in its *Trans Québec & Maritimes Pipelines Inc.* RH-1-2008 Decision.

> *The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:*
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);
> - enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
> - permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).
>
> *In the Board's view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline's revenue requirement, result in tolls that are just and reasonable.*[3]

All three standards must be met, and none ranks in priority to the others. To that point, the Ontario Energy Board ("OEB") articulated the legal requirements for satisfying the Fair Return Standard in Canada in its 2009 Generic Cost of Capital Order as follows:

> *The Board affirms its view that the Fair Return Standard frames the discretion of a regulator, by setting out the three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. Notwithstanding this obligation, the Board notes that the Fair Return Standard is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.*[4]

***

[3] National Energy Board RH-2-2004 Reasons for Decision, TransCanada PipeLines Ltd, Phase II, April 2005, at 17.

[4] Ontario Energy Board, EB-2009-084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at i.

> *… all three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate consideration to the comparability test is not sufficient to meet the [Fair Return Standard].*[5]

The Board embraces the same legal standards for the application of the Fair Return Standard as those put forth by the NEB, the OEB and those established through Canadian and U.S. common law. In that regard, the Board has stated:

> *In carrying out its duties under the Act the Board is required by Section 4 of the EPCA to observe the power policy of the Province as set out in Section 3 of the EPCA, and to apply tests which are consistent with generally accepted sound public utility practice. Section 3(a)(iii) of the EPCA provides that the rates to be charged for the supply of power should provide sufficient revenue to enable the utility to earn a just and reasonable return so that it is able to achieve and maintain a sound credit rating in the financial markets of the world.*[6]

In 2019, the Board cited its 2009, 2013 and 2016 Orders which addressed the three elements of the fair return standard directly, as follows: "To be considered fair the return must be commensurate with the return on investments of similar risk and sufficient to assure financial integrity and to attract necessary capital."[7] In 2019, the Board reiterated the 2009 Order as follows: "All three requirements must be met and no one requirement takes precedence over the other two. Determining a fair return involves an assessment of both the utility's capital structure and return on equity, in the context of the current capital market conditions and the utility's risk profile."[8] In 2022, the Board approved a settlement agreement and stated that the return on common equity and the agreed-upon common equity ratio were consistent with the fair return principle.[9]

The assessment of whether the Fair Return Standard has been met requires an examination of the required returns by investors in comparable-risk enterprises. Investors consider whether

5 Ibid, at 19.
6 Order No. P.U. 18(2016), at 10.
7 Order No. P.U. 2(2019), at 12.
8 Order No. P.U. 2(2019), at 12.
9 Order No. P.U. 3(2022), at 5.

there are alternative investment opportunities that would provide a better return for the same level of risk. This weighing of alternatives and the highly-competitive nature of capital markets causes stocks and bonds to settle on a price that provides investors with a return that is adequate for the risks involved. Thus, for any given level of risk, there is a corresponding return that investors expect in order to take on that risk and not invest their money elsewhere. That return is referred to as the "opportunity cost" of capital or "investor-required" return.

In addition to setting the fair return at the "opportunity cost" of capital, a fair return must also be adequate to maintain the financial integrity of the utility, which requires a return sufficient to maintain credit metrics such that the utility can maintain a favorable credit rating in order to minimize debt costs and provide lenders assurance that the company's earnings are adequate to meet its fixed obligations. Finally, a fair return must be sufficient to attract incremental capital on reasonable terms and conditions, to the benefit of both investors and customers.

B. The Stand-Alone Principle

The Stand-Alone Principle provides that the utility must be regulated as if it were a stand-alone entity, raising capital on the merits of its own business and financial characteristics. In this way, capital may be efficiently allocated, with each business segment earning a return based on its own unique set of risks and business characteristics regardless of affiliations within the holding company structure. In order to establish a fair return and satisfy the Stand-Alone Principle, the utility must be allowed a return sufficient to meet all three requirements of the Fair Return Standard on the basis of the utility's individual merits.

C. The Relationship Between Capital Structure and ROE

The cost of common equity depends in part on the company's capital structure. The equity ratio and equity rate of return must therefore be considered together to determine whether the Fair Return Standard has been met. Other factors being equal, firms with lower common equity ratios require higher rates of return to compensate shareholders for the additional financial risks. Consequently, when a regulator approves a capital structure, that decision impacts the required rate of return on common equity.

The risk to the earnings stream of the company is a function of both its business and financial risk. Business risk refers to the political and regulatory environment in which the company operates and the operational and competitive forces that could potentially exert pressure on earnings. Financial risk refers to the amount of debt in the utility's capital structure and the extent to which fixed debt obligations must be met before utility shareholders receive their returns. Both business and financial risks therefore need to be considered when setting the capital structure.

III. ECONOMIC AND CAPITAL MARKET CONDITIONS

A. Summary and Relevance to Utility Cost of Capital

Utilities raise debt and equity in a global market influenced by macroeconomic fundamentals, capital markets and central bank policies. The cost of debt for utilities is observable, but the cost of equity must be estimated with an informed view of the macroeconomic and capital market factors that impact the analysis. Projections of real GDP growth, inflation and interest rates are direct inputs to the cost of capital models. Likewise, the cost of equity for regulated utilities is influenced by factors such as central bank policy, investor confidence, and uncertainty and volatility in financial markets. Each of these factors is discussed in this section of our report, starting with macroeconomic conditions in Canada and the U.S.

In summary, there has been a fundamental shift in the economy and capital markets since March 2021 (when our analysis was conducted for Newfoundland Power's 2022/2023 General Rate Application ("GRA")), and cost of capital (along with other input costs, including labor) is higher for all companies, including utilities. This shift has occurred in large part because the extended period of declining interest rates (which began in 1982 and accelerated in the years after the financial crisis of 2008-2009) and low inflation has come to an end. Figure 3 provides a comparison of key economic and market indicators in August 2023 to those in March 2021.

Figure 3: Comparison of Key Economic and Market Indicators

Indicator	March 2021	August 2023
Bank of Canada Overnight Rate	0.25%	5.0%
10-year Government of Canada bond	1.50%	3.65%
30-year Government of Canada bond	1.94%	3.50%
A-rated Canadian utility bond	3.24%	4.98%
Consumer Price Inflation – Canada	2.2%	4.0%
Spread between 2 yr /10 yr Treasury bond	1.24%	(1.05%)
TSX Volatility Index	13.0	11.2
State Street Investor Confidence Index – U.S.	91.9	96.8

The Figure above shows that interest rates on government bonds and utility bonds have increased by 156 to 215 basis points depending on the security, inflation increased substantially in 2022-23 after a prolonged period of relative price stability, the Bank of Canada has raised its policy interest rate significantly to combat much higher inflation, and the yield curve inverted as interest rates on shorter dated government bonds exceed those on longer dated maturities due to uncertainty around the longer term economic and inflation outlook. Stock market volatility is nonetheless down while investor confidence has improved as reflected in a relatively strong stock market, although utility shares are down. All of these indicators are considered and discussed in more detail in this section of our report, starting with macroeconomic conditions in Canada and the U.S. Some indicators are described for context, and others because they are direct inputs to the models used to estimate the return on equity.

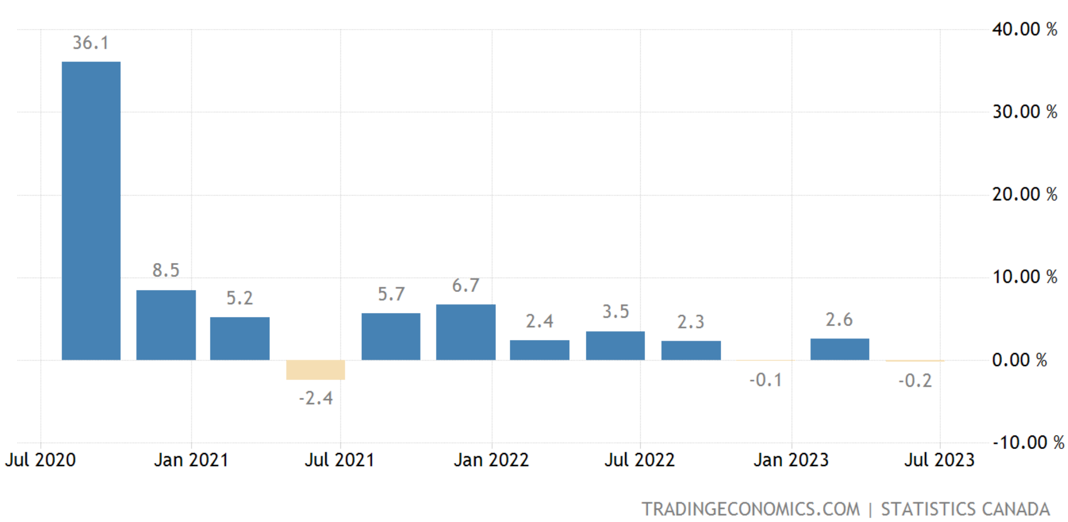
B. Macro-Economic Conditions

At the time of the 2022/2023 GRA filing by Newfoundland Power in May 2021, the economies in both Canada and the U.S. were expected to emerge from sharp contractions in 2020 precipitated by the COVID-19 pandemic, which forced the closure of many businesses as economies went into lockdown to control the spread of the virus. Extraordinary policy measures were necessary from central banks and federal governments in both Canada and the U.S. to stabilize the financial system and support economic growth in the immediate aftermath of the pandemic. That policy response caused a precipitous drop in interest rates on government and corporate bonds. Those bond yields, however, have increased significantly since July 2020 as investors anticipated the economic recovery and responded to the sharp increase in inflation. Although inflation has eased from the highest levels in almost 40 years as central banks in Canada and the U.S. have aggressively tightened monetary policy to slow the economy, inflation has proven more persistent than expected, and central banks have indicated that they may need to raise short-term rates further in order to bring inflation down to the target range of 1-3 percent in Canada and 2 percent in the U.S.

1. Canada

GDP is an important indicator of economic activity that is a direct input to the multi-stage DCF model and also signals demand for all inputs to the economy, including capital. The Canadian economy shrank 5.4 percent in 2020 due to the spread of COVID-19, before recovering in 2021 as restrictions were eased. Figure 4 shows that real GDP grew steadily in the first three quarters of 2022, at an annualized rate between 2.3 percent and 3.5 percent, but was nearly unchanged in the fourth quarter of 2022. GDP growth resumed in the first quarter of 2023 at an annualized rate of 2.6 percent but unexpectedly contracted in the second quarter as tighter monetary policy slowed economic growth.

Figure 4: Canadian Real GDP Growth[10]



[10] https://tradingeconomics.com/canada/gdp-growth-annualized

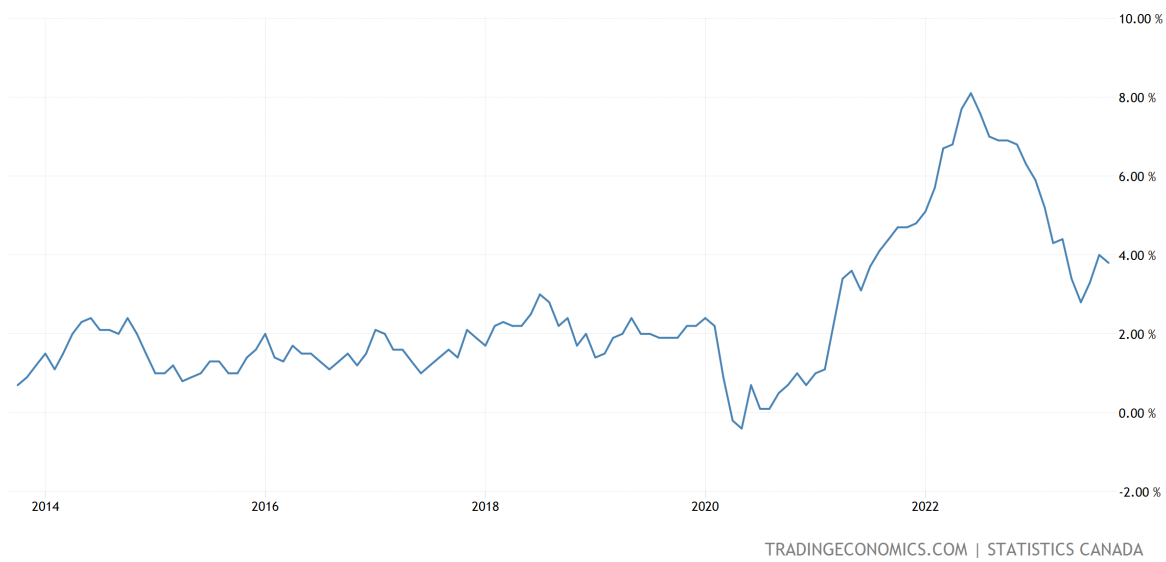
The unemployment rate declined steadily for much of 2021 from a peak of 13.7 percent in May 2020 and was slightly over 5 percent for most of 2022. As shown in Figure 5, the unemployment rate has increased in recent months to 5.5 percent, as tighter monetary policy has constrained the pace of hiring. While unemployment is not a direct input to the cost of capital models, it provides another indicator of the strength of the economy.

Figure 5: Canadian Unemployment Rate[11]

[11] https://tradingeconomics.com/canada/unemployment-rate

As shown in Figure 6, consumer prices in Canada generally have risen less than 2.0 percent in the past decade, but the inflation rate increased at a 30-year high of 4.8 percent in 2021 and 6.3 percent in 2022. This is below the peak of 8.1 percent in June 2022, which was the highest rate in 40 years. The annual inflation rate in September 2023 increased from the June low to 3.8 percent, while the core trimmed-mean rate, which is closely watched by the Bank of Canada, was 3.7 percent.[12] Inflation is an important factor in the cost of capital and is also an input to the multi-stage DCF model. Higher inflation rates drive higher capital costs as investors seek more stable "real" returns (after the effects of inflation).

Figure 6: Canadian Inflation Rate[13]



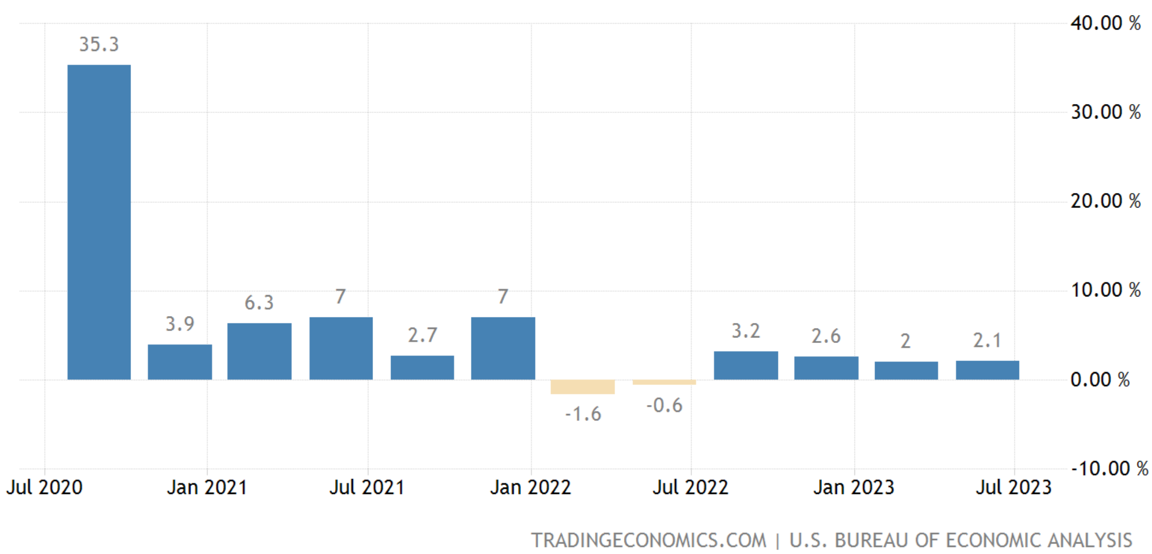
12 CPI-trim is a measure of core inflation that excludes CPI components whose rates of change in a given month are located in the tails of the distribution of price changes.

13 https://tradingeconomics.com/canada/inflation-cpi

2. United States

After experiencing steady economic growth from 2017-2019, as in Canada, the consequences of the COVID-19 pandemic forced the U.S. economy into a sharp recession in 2020. GDP growth resumed in 2021 as the economy recovered, but unexpectedly contracted in the first and second quarters of 2022 (a technical recession), as shown in Figure 7. GDP has since expanded at an annualized rate between 2.0 percent and 3.2 percent in the past four quarters.

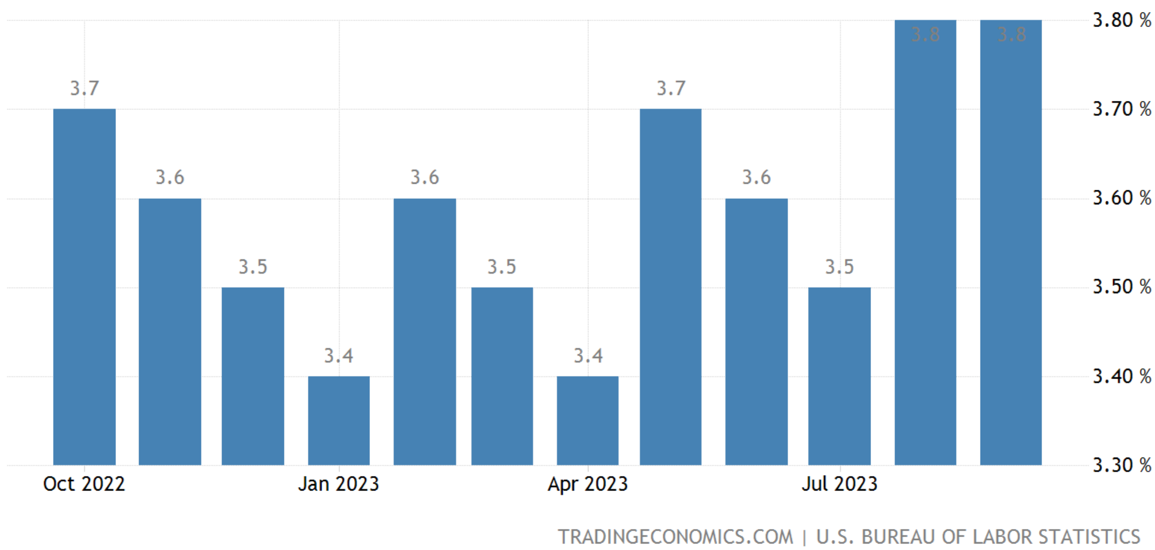
Figure 7: U.S. Real GDP Growth[14]



[14] Source: https://tradingeconomics.com/united-states/gdp-growth.

After reaching a low of 3.5 percent in January 2020, the U.S. unemployment rate spiked to 14.7 percent in April 2020 as businesses were forced to close due to COVID-19. Figure 8 shows that the U.S. unemployment rate has ranged from 3.4 to 3.8 percent over the past 12 months.

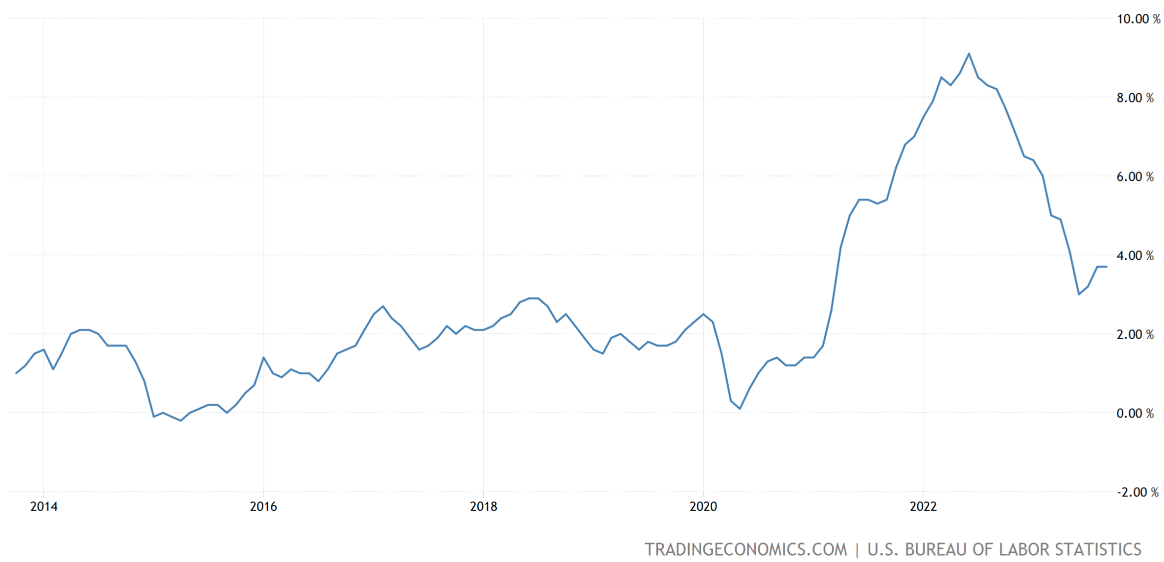
Figure 8: U.S. Unemployment Rate[15]



[15] Source: https://tradingeconomics.com/united-states/unemployment-rate

The U.S. Consumer Price Index ("CPI") increased at an annual rate of 1.8 percent in 2019 and 1.2 percent in 2020. Inflationary pressure mounted with the Bureau of Labor Statistics reporting that the CPI increased at an annualized rate of over 8 percent in every month from March through September 2022 (a level not seen since the early 1980s), before declining to 7.1 percent in November 2022. As shown in Figure 9, the CPI in September 2023 increased at an annualized rate of 3.7 percent as more restrictive monetary policy helped ease price pressure on food and energy, although core inflation (which excludes more volatile food and energy prices) remained at 4.1 percent.

Figure 9: U.S. Consumer Price Inflation[16]



C. Central Bank and Federal Government Policies

The policies of central banks directly impact interest rates, inflation, and the pace of economic growth. All of these factors influence the cost of capital for utilities. Central banks and federal governments in both Canada and the U.S. took aggressive steps to stabilize financial markets in the Spring of 2020 and to provide ongoing support for the economies of both countries in response to the economic effects of COVID-19. During this period, interest rates on government bonds were being driven by actions of central banks and not just the decisions of investors in the bond markets. In the Spring of 2022, central banks in both countries embarked on a path of

[16] Source: https://tradingeconomics.com/united-states/inflation-cpi

tightening monetary policy in response to stronger employment and excess demand, which have contributed to the highest inflation in 40 years.

1. Canada

In response to inflation being higher than its target range of 1-3 percent (consumer prices increased by 6.3 percent in 2022), the Bank of Canada ("BOC") raised the overnight rate on multiple occasions from 0.25 percent in March 2022 to 5.00 percent in July 2023. The BOC held the overnight rate steady at its October 2023 meeting, but noted that core inflation has been more persistent than anticipated:

> *CPI inflation has been volatile in recent months—2.8% in June, 4.0% in August, and 3.8% in September. Higher interest rates are moderating inflation in many goods that people buy on credit, and this is spreading to services. Food inflation is easing from very high rates. However, in addition to elevated mortgage interest costs, inflation in rent and other housing costs remains high. Near-term inflation expectations and corporate pricing behaviour are normalizing only gradually, and wages are still growing around 4% to 5%. The Bank's preferred measures of core inflation show little downward momentum.*[17]

In its October 2023 Monetary Policy Report, the BOC underscored several key messages about the outlook for the economy:[18]

1) Inflation continues to decline gradually in most economies. Higher policy interest rates and tight financial conditions are contributing to slowing global demand growth and easing price pressures, although inflation in services prices is sticky.

2) Global economic growth is slowing. While the US economy has been surprisingly robust, the weakness in China has been more pronounced than expected in the July Report.

3) In Canada, higher interest rates are working to ease price pressures, and consumer price index (CPI) inflation has come down significantly from its peak in June 2022. However, progress toward the 2% target is proving to be slow, and the pace of future declines in inflation remains uncertain. Core inflation has been more persistent than expected.

4) At the same time, demand growth has eased and supply is rising. Evidence suggests that the economy is approaching balance. With supply growing faster than demand, price pressures are expected to gradually moderate further.

[17] Bank of Canada, Press Release issued October 25, 2023.
[18] Bank of Canada, Monetary Policy Report, October 25, 2023, at 5.

Economic activity is forecast to be modest through most of 2024, with annual growth in gross domestic product (GDP) just under 1%. As past interest rate increases continue to work their way through the economy, they will weigh on household spending and business investment. Weak foreign demand is also expected to slow export growth. GDP growth is projected to rise to about 2½% in 2025.

5) Inflation is now projected to stay around 3½% until the middle of 2024. As the economy moves into excess supply and price pressures moderate, inflation is forecast to ease to about 2½% in the second half of 2024 and then return to target in 2025.

6) A considerable amount of uncertainty surrounds the forecast. Three-month rates of core inflation have remained elevated, in the range of 3½% to 4% for the past year. Near-term inflation expectations are still high, and there is a risk that they could become a driver of wage- and price-setting behaviour.

7) Another risk is that the war in Israel and Gaza spreads further into a broader regional conflict, disrupting oil supplies and leading to a resurgence of inflation in energy prices.

8) Overall, there is more evidence that the economy is slowing, which is relieving price pressures. But the progress to price stability is slow, and inflationary risks have increased.

2. United States

Monetary policy has followed a similar path in the U.S., with the U.S. Federal Reserve (the "Fed") raising the federal funds rate to combat higher than expected inflation. The Fed raised the discount rate on numerous occasions from a range of 0.00-0.25 percent in March 2022 to a range of 5.25-5.50 percent in July 2023, the highest level since March 2001. At its most recent meeting, the Fed recommitted to its objectives and present course of action noting:[19]

> *The Committee seeks to achieve maximum employment and inflation at the rate of 2 percent over the longer run. In support of these goals, the Committee decided to maintain the target range for the federal funds rate at 5-1/4 to 5-1/2 percent. The Committee will continue to assess additional information and its implications for monetary policy. In determining the extent of additional policy firming that may be appropriate to return inflation to 2 percent over time, the Committee will take into account the cumulative tightening of monetary policy, the lags with which monetary policy affects economic activity and inflation, and economic and financial developments. In addition, the Committee will continue reducing its holdings of Treasury securities and*

[19] Federal Reserve Press Release, September 20. 2023.

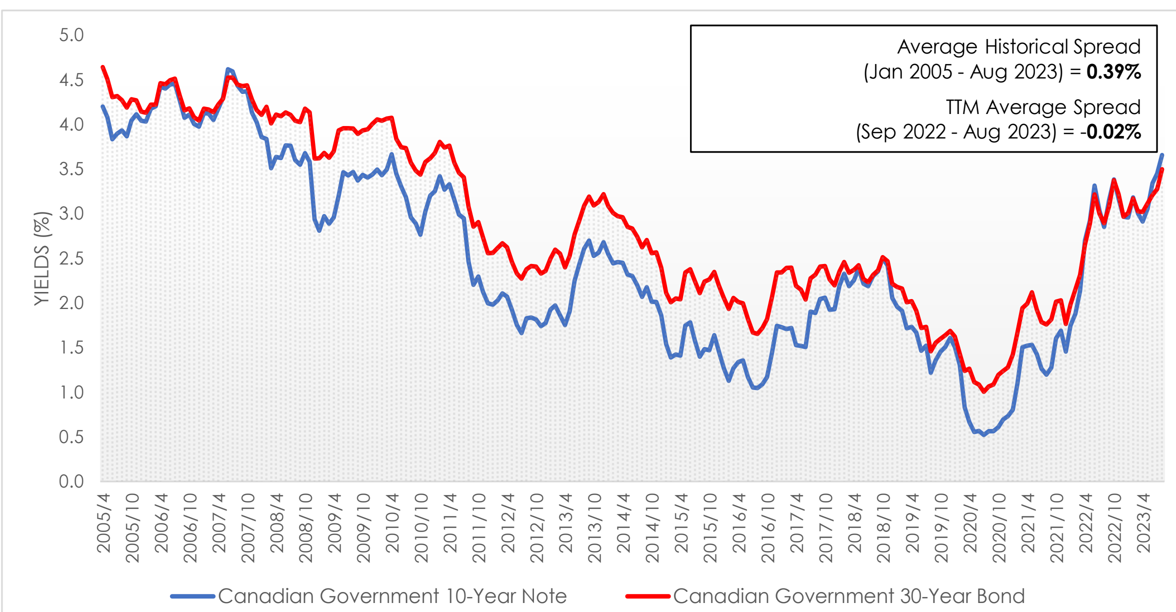
> *agency debt and agency mortgage-backed securities, as described in its previously announced plans. The Committee is strongly committed to returning inflation to its 2 percent objective.*

D. Overview of Bond Yields and Equity Markets

1. Interest Rates

Bond yields are a direct indicator of the cost of capital, as they reflect the level of interest required to compensate debt (but not equity) investors in the current market. Bond yields are also a direct input to the CAPM and Risk Premium models. Figure 10 shows that both the 10- and 30-year Canadian government bond yields increased sharply after trading at or near all-time lows in July 2020. Average yields on 10-year government bonds in March 2021 (when our analysis for Newfoundland Power's 2022/2023 GRA was conducted) were 1.50 percent, as compared to 3.65 percent in August 2023. For 30-year government bonds, the average yield in March 2021 was 1.94 percent, compared to 3.50 percent in August 2023. The spread between 10- and 30-year Canadian government bonds was 44 basis points in March 2021 and minus 16 basis points in August 2023, reflecting current uncertainty regarding both the economy and inflation. The average historical spread since January 2005 has been 39 basis points.

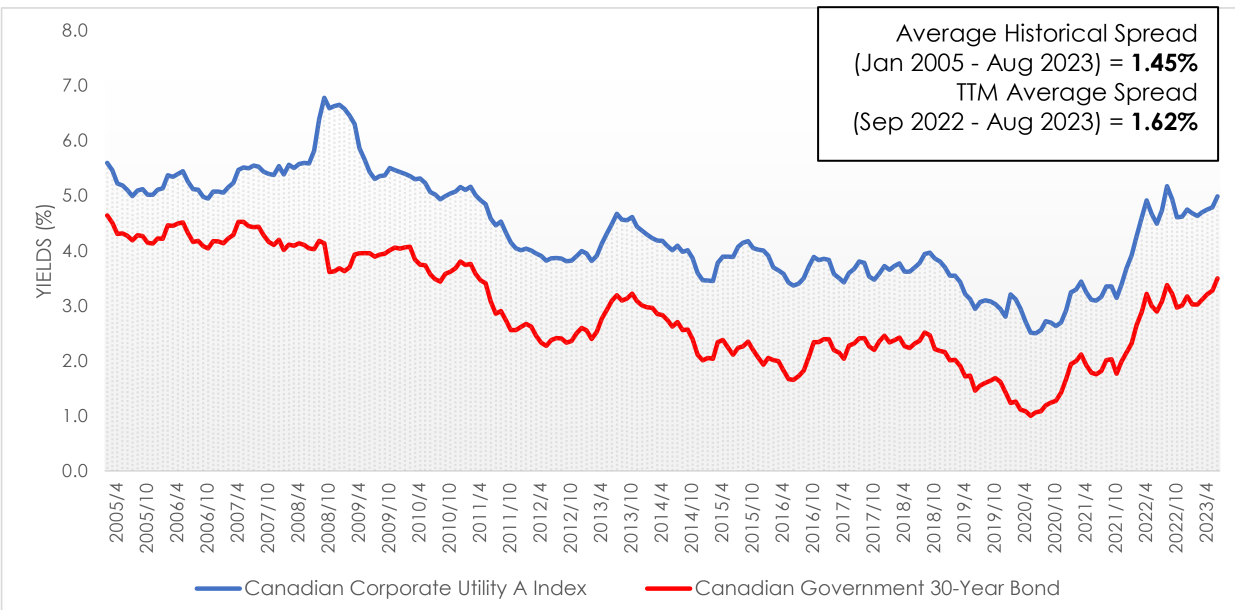
Figure 10: Canadian Government Bond Yields - 10-Year and 30-Year[20]



[20] Bloomberg series GCAN10YR and GCAN30YR as of August 31, 2023.

Yields on Canadian utility bonds have followed a similar pattern. As Figure 11 illustrates, the Canadian Utility "A" rated bond yield index was 3.24 percent in March 2021 compared to 4.98 percent in August 2023. The spread between Canadian A-rated utility bonds and the 30-year Government of Canada long bond increased from 130 basis points in May 2021 to 149 basis points in August 2023, slightly above the historical average of 145 basis points. The higher spread in August 2023 indicates that bond market participants are slightly more concerned about credit risk for corporate borrowers (even A-rated utilities) than in March 2021.

Figure 11: Canadian Utility "A" Rated Bond vs. 30-Year Canada Long Bond[21]



[21] Bloomberg series C29530Y and GCAN30YR as of August 31, 2023.

As shown in Figure 12, forecast 10-year government bond yields from Consensus Economics are lower than current interest rates in Canada (which are about 4.1% in late October 2023) and in the U.S. (which are around 5.0%). This suggests that forecasters believe that central banks are nearing the end of monetary policy tightening and are expecting that an economic slowdown will ease inflation and the demand for money.

Figure 12: Long-Term Forecast for 10-Year Government Bond Yields[22]

	2024	2025	2026	2027	2028	2029-2033
Canada	3.0%	3.2%	3.2%	3.2%	3.2%	3.2%
U.S.	3.5%	3.4%	3.4%	3.4%	3.4%	3.4%

2. Yield Curve

The yield curve measures the difference between long-term and short-term interest rates. It is not a direct input to the models, but the cost of capital for utilities is more determined by long-term rates, so it is an indicator. A flat or inverted yield curve occurs when long-term interest rates are equal to or less than short-term interest rates, which usually occurs prior to a recession, while a steepening yield curve occurs when the difference between long-term interest rates and short-term interest rates is increasing and indicates that the economy is entering a period of expansion.[23]

To test this measure, we calculated the difference between the yield on the 10-year government bond and the 2-year government bond ("bond spread") from March 2021 to August 2023. We selected the 10-year government bond yield to represent long-term interest rates and the 2-year government bond to represent short-term interest rates. In Canada, the bond spread was 124 basis points in March 2021 versus negative 105 basis points in August 2023, while in the U.S., the monthly average bond spread was 146 basis points in March 2021 versus negative 73 basis points in August 2023. The yield curve became inverted in July 2022 in both countries, reflecting

[22] Consensus Forecasts by Consensus Economics Inc., Survey Date April 11, 2023, at 3 and 28.
[23] "What is a yield curve", Fidelity.com. https://www.fidelity.com/learning-center/investment-products/fixed-income-bonds/bond-yield-curve

greater uncertainty regarding economic growth, due to much tighter monetary policy in response to inflationary pressure. A negative bond spread should be expected to shift to a normal positive relationship through either higher long-term yields or lower near-term yields. For the time being, Concentric is of the view that the forecast 10-year bond yield with a normalized 10-30 year spread is a reasonable indicator of the forward-looking 30-year bond. The referenced bond spreads are shown in Figure 13.

Figure 13: 10-year Government Bond Yield Minus 2-year Bond Yield[24]

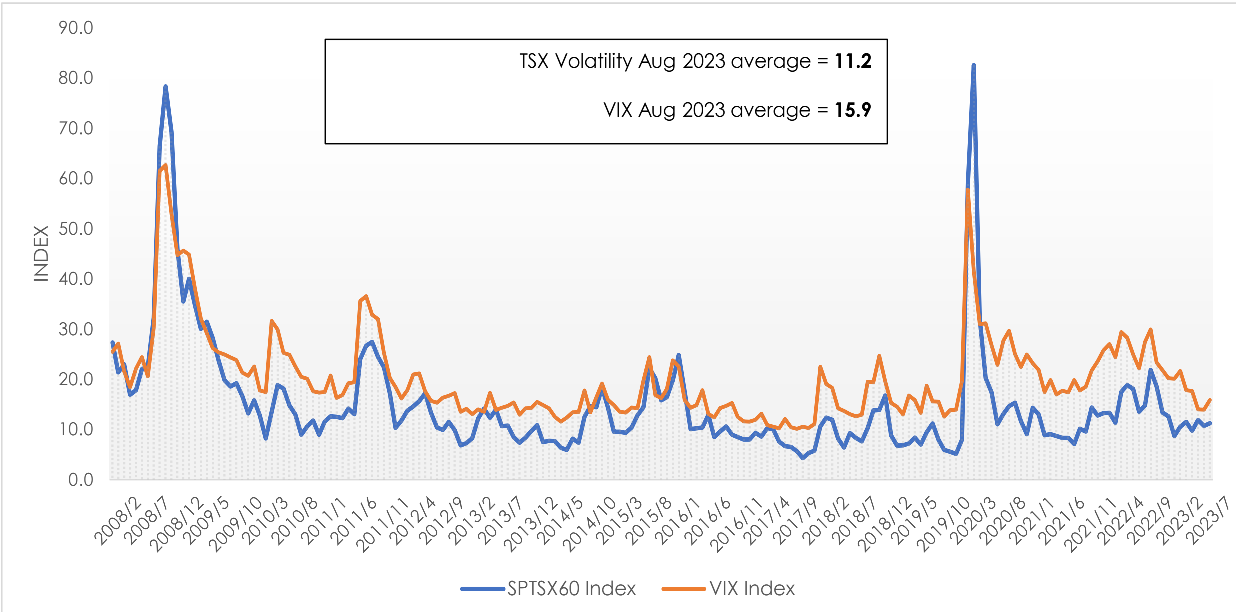
3. <u>Volatility in Equity Prices</u>

We look at volatility in equity prices as an indicator of investor risk. In general, periods of heightened market volatility signal greater risk to investors, causing an increase in the required return to absorb that risk, and vice versa when volatility decreases. As of August 2023, volatility in equity markets has receded from extreme levels in both countries during the pandemic and is slightly below the long-term median of 12.3 in Canada and below the long-term median of 17.8

[24] Federal Reserve Bank of St. Louis, 10-Year Treasury Constant Maturity Minus 2-Year Treasury Constant Maturity [T10Y2Y], retrieved from FRED, Federal Reserve Bank of St. Louis.

in the U.S., as shown in Figure 14. By comparison, volatility readings were higher in March 2021, at 13.0 in Canada and 21.8 in the U.S.

Figure 14: Canadian and U.S. Volatility Indexes[25]



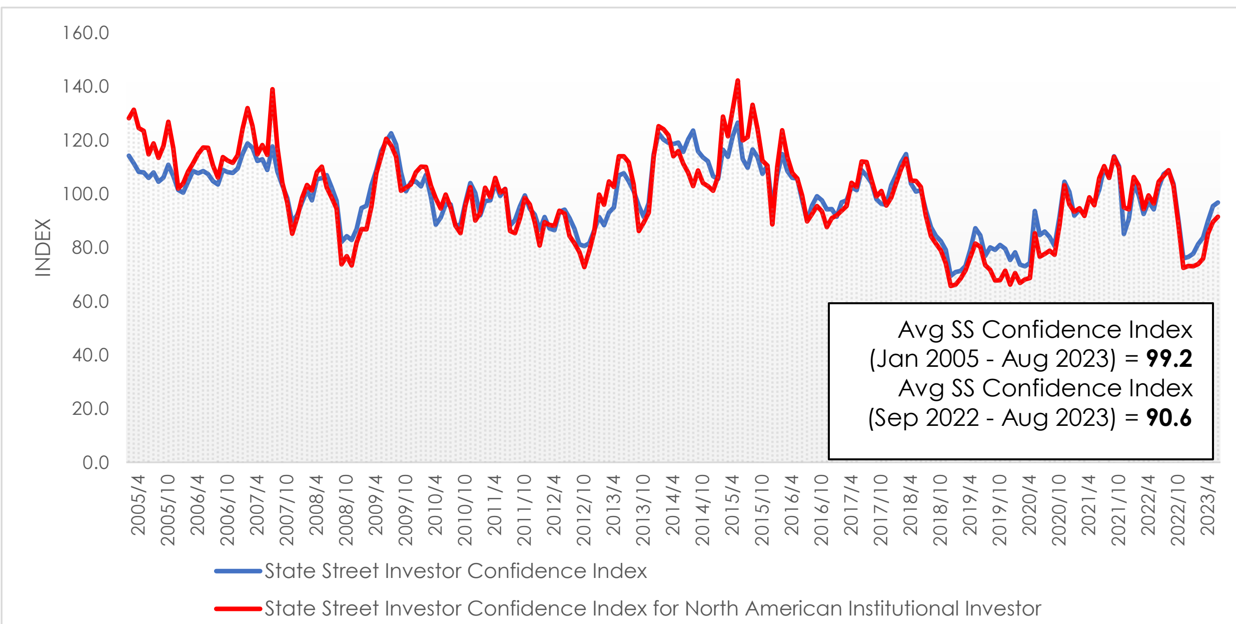
The sudden and dramatic spike in volatility in 2020 reflected the prevailing uncertainty and fear among equity investors. Volatility in equity markets declined in both Canada and the U.S. after it became apparent to investors that the aggressive monetary and fiscal policy response was having the desired impact on the economy and financial markets, although volatility has risen again in October 2023 as markets weigh the impact of interest rate conditions and increasing global conflicts on economic growth.

[25] Bloomberg Professional. Data through August 31, 2023.

4. Investor Confidence

Another indicator of market risk is investor confidence. The investor confidence index published by State Street Bank in the U.S. provides a quantitative measure of global risk tolerance. Figure 15 shows that investor confidence in 2020 was generally lower than during the global economic crisis of 2008-2009. After peaking in May 2018 at 114.80, investor confidence turned sharply lower and remained below 100 in all but two months from September 2018 through July 2021. After readings above 100 from August through November 2022, the index declined sharply in December 2022 and remained below 90 through June 2023. The August 2023 reading of 96.8 is below the long-term average of 99.2 but higher than the March 2021 level of 91.9.

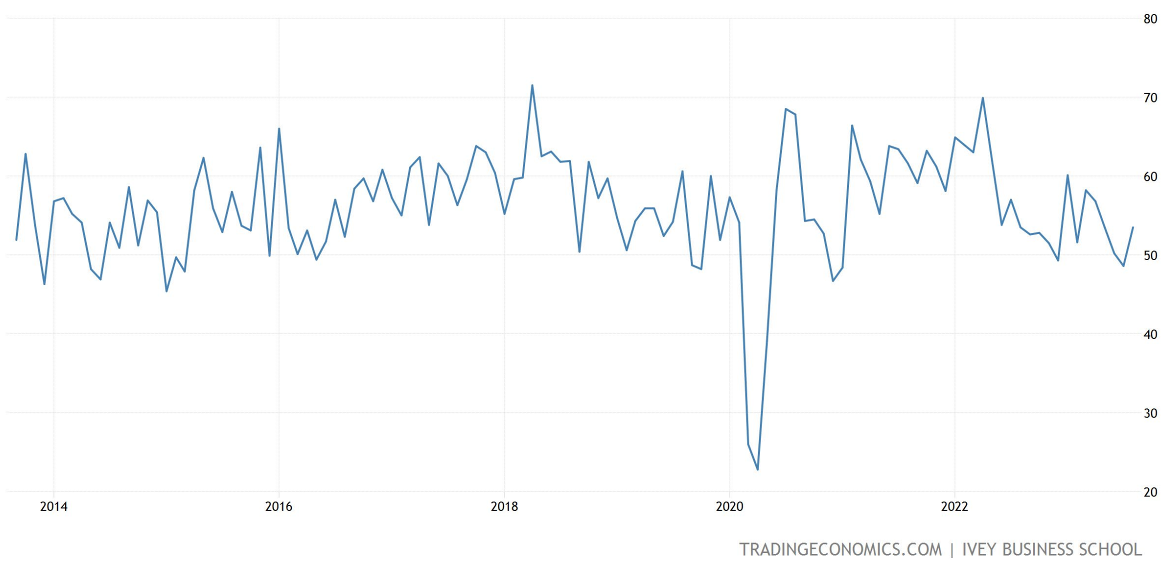
Figure 15: State Street Investor Confidence Indices[26]



[26] Bloomberg SSICCONF Index and SSICAMER Index as of August 31, 2023.

In Canada the Richard Ivey School of Business at the University of Western Ontario publishes a monthly Purchasing Managers Index ("PMI") that measures business confidence. The PMI is an economic index which measures the month-to-month variation in economic activity as indicated by a panel of purchasing managers from across Canada, and is based on one question only: "Are your purchases (in dollars) higher, the same, or lower than the previous month?" As shown in Figure 16, the Index fell from a 16-year high of 74.2 in March 2022 to 53.4 in August 2023, but up from 48.6 in the prior month. The Index is used as a leading indicator of price levels, supplier delivery times, job creation and inventories.

Figure 16: Canadian Business Confidence Index[27]



5. <u>Integration of Canadian and U.S. Economies and Capital Markets</u>

As the Board considers the applicability of a mix of U.S. and Canadian market and company data, it must consider the comparability of the risk environment from an investor's perspective, as risk drives return expectations. In a world of increasingly linked economies and capital markets, investors seek returns from a global basket of investment options. Investors distinguish between risks on a country-to-country basis, factoring in the comparability of the economic, business and political environments.

[27] https://tradingeconomics.com/canada/business-confidence .

Country-specific economic, business and political conditions that affect investment risk can be measured through a variety of qualitative and quantitative metrics. One such measure, produced by The Economist Intelligence Unit ("EIU"), rates Canada and the U.S. precisely the same from an overall country risk perspective. Both are rated as A, with AAA being the highest rating.[28] The Economist provides the following description of its country risk ratings:

> *The Economist Intelligence Unit's Country Risk Service produces reports on 100 emerging markets and 20 OECD countries. These country-specific reports are complemented by this Risk ratings review, which analyses regional and global risk trends. The main focus of the ratings is on three risk categories to which clients can have direct exposure: sovereign risk, currency risk and banking sector risk. We also publish ratings for political risk and economic structure risk, as well as an overall country credit rating. The ratings are measured on a scale of 0-100. Higher scores indicate a higher level of risk. The scale is divided into ten overlapping bands: AAA, AA, A, BBB, BB, B, CCC, CC, C, D. In the Risk ratings review, ratings for a region are defined as the unweighted average of the ratings for all the countries being assessed in that region.*[29]

Figure 17 summarizes the EIU country risk ratings for Canada and the U.S. as of August 2021.

Figure 17: Country Risk Ratings

	Canada	U.S.
Sovereign Risk Rating	A	AA
Currency Risk Rating	A	A
Banking Sector Risk Rating	AA	A
Political Risk Rating	AAA	AA
Economic Structure Risk Rating	A	A
Overall Country Risk Rating	A	A

This suggests that from a country risk perspective, Canada and the U.S. are highly comparable.

Allianz, a global financial services firm headquartered in Munich, Germany, assigns both Canada and the U.S. a country rating of AA1 based on an evaluation of several factors, including economic risk, business environment risk, political risk, commercial risk, and financing risk.[30] Allianz

[28] The Economist Intelligence Unit, Country Risk Service, Risk Ratings Review, August 2021, at 30.
[29] Ibid, at 28.
[30] Country Risk Report Canada (allianz.com); Country Risk Report United States (allianz.com)

reports that the U.S. is the top trading partner for Canada (accounting for 75.5% of exports and 48.5% of imports in 2021). Similarly, Canada is the top export market for the U.S. (at 17.5% in 2021) and the third leading import market (at 12.4%).

The magnitude and significance of trade between the two countries reflects the high degree of integration between the two economies. According to the U.S. Department of State: "The United States and Canada enjoy the world's most comprehensive trading relationship, which supports millions of jobs in each country. Canada and the U.S. are each other's largest export markets, and Canada is the number one export market for more than 30 U.S. States."[31] Canada is currently the U.S.'s second largest goods trading partner overall with $793 billion in total (two way) goods trade during 2022.[32] Although two way trade has decreased slightly from $US 2.17 billion per day in 2022 to $US 2.12 billion per day during the first seven months of 2023, it continues to demonstrate the high degree of economic integration between the two economies.

Exhibit JMC-2 presents several measures that reflect the overall economic and investment environment in Canada and the U.S. On balance, the economic and business environments of Canada and the U.S. are highly integrated and exhibit strong correlation across a variety of metrics, including GDP growth and government bond yields. From a business risk perspective, including overall business environment and competitiveness, Canada and the U.S. are ranked closely when compared against other developed and developing countries.

Based on these macroeconomic indicators, there are no fundamental dissimilarities between Canada and the U.S. (in terms of economic growth, inflation, or government bond yields) that would cause a reasonable investor to have a materially different return expectation for a group of comparable risk utilities in the two countries. Our cost of capital analysis is framed by the conclusion that Canada and the U.S. have comparable macroeconomic and investment environments. The National Energy Board ("NEB", now the "CER") reached a similar conclusion when it found: "the opportunity cost of capital is not significantly different between Canada and the U.S." The NEB concluded: "Based upon its assessment of overall risk of the Company (IPL) relative to U.S. and Canadian industrials, the Board concludes that the cost of equity should be equal to, or slightly less than, the opportunity cost of investments in such (U.S.) companies."[33]

[31] U.S. Department of State, https://www.state.gov/u-s-relations-with-canada
[32] https://www.census.gov/foreign-trade/balance/c1220.html
[33] RH-2-76 Part II, PDF pages 144-145.

The BCUC recently reinforced the appropriateness of using a North American approach when it determined:

> *On balance, we find that having a proxy group of North American comparators trumps any jurisdictional or structural differences. In making this determination, we rely on the facts that financial and capital markets are highly integrated and that utility regulatory regimes in North America are sufficiently similar for the purpose of establishing a comparable ROE.*[34]

In concurrence, we utilize both Canadian and U.S. proxy companies for our analysis.

E. Capital Market Conclusions

There has been a fundamental shift in capital market conditions since 2021, and the cost of capital (along with other input costs, including labor) is higher for all companies, including utilities. This shift has occurred in large part because the extended period of declining interest rates (which began in 1982 and which accelerated in the years after the financial crisis of 2008-2009) and low inflation has come to an end. Interest rates on government and corporate utility bonds reached all-time lows in 2020 before rebounding to levels in August 2023 that are 156 to 215 basis points higher than those in March 2021 (the date of the analysis in our report for Newfoundland Power's previous GRA). The future path of the costs of debt and equity will be influenced by the path of an uncertain economy and persistently higher inflation. In general, the low capital cost and low inflation environment of the past two decades has yielded to new economic circumstances requiring the upward repricing of capital, labor, and materials to reflect new market realities. These factors are captured in the models we have utilized to estimate the current cost of equity for Newfoundland Power, as discussed in the following sections.

IV. SELECTION OF PROXY COMPANIES

The ROE is a market-based concept and, given the fact that Newfoundland Power is not publicly-traded, it is necessary to establish a group of companies that are both publicly-traded and comparable to Newfoundland Power's business and financial characteristics to serve as its "proxy" for purposes of the ROE estimation process. Even if Newfoundland Power's regulated electric utility operations made up the entirety of a publicly-traded entity, transitory events could

34 British Columbia Utilities Commission Generic Cost of Capital Proceeding (Stage 1) Decision and Order G-236-23, September 5, 2023 at 16.

bias that entity's market value in one way or another over a given period of time. A significant benefit of using a proxy group is that it provides the ability to mitigate the effects of anomalous events that may be associated with any one company. The proxy companies used in our ROE analyses possess a set of business and financial characteristics that are similar to Newfoundland Power's regulated electric utility operations, and thus provide a reasonable basis for the derivation and assessment of ROE and capital structure estimates.

We developed three proxy groups for the ROE analysis. The first proxy group is comprised of publicly-traded, regulated Canadian electric and natural gas utility companies. Recognizing there are few publicly-traded companies in the utility sector in Canada, the only screening criterion was an investment grade credit rating, which all companies in the sector have. Fortis Inc. has been excluded from the Canadian proxy group because it is the parent company of Newfoundland Power. TC Energy (formerly TransCanada) has also been excluded because gas and oil pipeline companies arguably have greater risk than electric utility operations. The following six companies comprise the Canadian Proxy Group:

Figure 18: Canadian Proxy Group

Company	Ticker
Algonquin Power and Utilities Corp.	AQN
AltaGas Inc.	ALA
Canadian Utilities Limited	CU
Emera Inc.	EMA
Enbridge Inc.	ENB
Hydro One, Ltd.	H

Four of the six companies in the Canadian proxy group derive a significant percentage of their revenues/income from utility subsidiaries that operate in the U.S. and have a significant percentage of their total assets dedicated to U.S. operations. For example, the vast majority of Algonquin Power's utility operations are in the U.S., including its largest subsidiary Empire District Electric Co. (Missouri and Kansas); AltaGas derives the majority of its normalized EBITDA and income before taxes from gas distribution operations in the U.S. (Maryland, Virginia, and Washington DC); Emera Inc. has significant U.S. electric and gas operations through its Tampa Electric Company (Florida), Peoples Natural Gas (Florida), and New Mexico Gas subsidiaries. Enbridge Inc. also has significant U.S. operations including its oil and natural gas pipeline business that was acquired from Spectra Energy Corp in 2017.[35] Figure 19 summarizes the percentage of Canadian and U.S. operations for each of these companies in 2022 based on available segment data.

Figure 19: Percentage of Canadian and U.S. Operations

	Canadian	**U.S.**
Algonquin Power and Utilities Corp.[36]	3%	83%
Alta Gas Inc.[37]	39%	61%
Canadian Utilities Limited[38]	93%	0%
Emera Inc.[39]	23%	70%
Enbridge Inc.[40]	52%	48%
Hydro One, Ltd.	100%	0%

The second proxy group is comprised of U.S. electric utility companies that would be considered by investors as generally comparable in risk to Newfoundland Power. To obtain companies of like-risk, we applied a number of screens to develop a group of companies that is primarily engaged in the provision of regulated electric utility service. Starting with the 36 domestic companies Value Line classifies as Electric Utilities, we further screened for companies that meet the following criteria:

a) Credit ratings of at least BBB+ from S&P or Baa1 from Moody's;

b) Consistently pay quarterly cash dividends that have not been reduced in the previous two years;

[35] The recently announced acquisition of Dominion Energy's natural gas utilities will further expand Enbridge's U.S. market presence. https://www.enbridge.com/media-center/news/details?id=123779#:~:text=(%22Enbridge%22%20or%20the%20%22,)%2C%20comprised%20of%20%24US9.

[36] Percentage of regulated revenue, as reported in Algonquin Power's 2022 SEC Form 10-K, at 10.

[37] Percentage of normalized EBITDA, as reported in AltaGas Ltd's 2022 MD&A and Financial Statements, at 32.

[38] Percentage of assets, as reported in Canadian Utilities Ltd. 2022 Consolidated Financial Statements, at 16-17. Canadian Utilities does not have regulated operations in the U.S. The company only reports revenues and net income for Canada, Australia, and the Caribbean.

[39] Percentage of revenues, as reported in Emera, Inc.'s 2022 Consolidated Financial Statements, at 28.

[40] Percentage of revenues, as reported in Enbridge Inc.'s 2022 Consolidated Financial Statements, at 30.

c) Positive earnings growth rate projections from at least two sources;

d) At least 70 percent of operating income derived from regulated operations in the period from 2020-2022;

e) At least 80 percent of regulated operating income derived from electric utility service in the period from 2020-2022; and

f) Not involved in a merger or other significant transformative transaction during the evaluation period.

The following U.S. electric utility companies met the screening criteria:

Figure 20: U.S. Electric Proxy Group

Company	Ticker
Alliant Energy Corp.	LNT
American Electric Power Company	AEP
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy Inc.	EVRG
Eversource Energy	ES
NextEra Energy Inc.	NEE
OGE Energy Corp.	OGE
Pinnacle West Capital Corp.	PNW
Portland General Electric Company	POR

The third proxy group is comprised of the four Canadian investor-owned utilities that are primarily engaged in the provision of electricity (Algonquin Power & Utilities Corp., Canadian Utilities Limited, Emera Inc. and Hydro One Ltd) plus all ten U.S. electric utilities in Figure 21. This group is referred to as the North American Electric proxy group.

Figure 21: North American Electric Proxy Group

Company	Ticker
Algonquin Power & Utilities Corp	AQN
Canadian Utilities Limitedtd.	CU
Emera Inc.	EMA
Hydro One, Ltd.	H
Alliant Energy Corp.	LNT
American Electric Power Company	AEP
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy Inc.	EVRG
Eversource Energy	ES
NextEra Energy Inc.	NEE
OGE Energy Corp.	OGE
Pinnacle West Capital Corp.	PNW
Portland General Electric Company	POR

Exhibit JMC-3 provides additional information on the proxy group screening process.

Canadian regulators have accepted the use of U.S. data and proxy groups to estimate the allowed ROE for Canadian regulated utilities. As noted, the British Columbia Utilities Commission ("BCUC"), for example, recently accepted the use of a North American proxy group that included both Canadian and U.S. utilities in the ROE analysis.[41] The BCUC explained its decision to use a North American proxy group as follows:

> *Finally, we reject RCIA's submission for the BCUC to only use Canadian data for the Canadian proxy group because it is country and market specific. Instead, we agree with FortisBC that there is ample basis to include US data in our ROE analysis because:*

[41] British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 1), Order G-236-23, September 5, 2023, at 16-17.

> *There are insufficient comparators to each of FEI [FortisBC Energy Inc.] and FBC [FortisBC Inc.] in Canada to allow the BCUC to use only data pertaining to Canadian counterparts;*
>
> *Both experts agree that the inclusion of US data is appropriate and both favour the use of North American proxy groups;*
>
> *The BCUC's 2016 Decision used US proxy groups results, citing both increasing integration and the scarcity of Canadian publicly traded utilities; and*
>
> *Other Canadian regulators (and more recently FERC) have taken a similar approach; and the extent of North American financial and capital markets integration has only increased over time.*

The Canadian Energy Regulator (formerly known as the NEB), the OEB and the Régie de l'energie (Quebec) have also accepted the use of U.S. data and proxy groups for purposes of establishing the allowed ROE and common equity ratio for Canadian electric and gas utilities.[42] In summary, multiple regulatory authorities in Canada have recognized that Canadian utility companies are competing for capital in global financial markets and that Canadian data are limited by the small number of publicly-traded utilities. Regulators have also recognized the integrated nature of Canadian and U.S. financial markets, and the similarity of the utility regulatory regimes.

V. METHODS FOR ESTIMATING THE COST OF EQUITY

Analysts use multiple approaches to estimate the cost of common equity. The required ROE can be estimated using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding required equity returns, adjusted for certain incremental costs and risks. Quantitative models produce a range of results from which the market-required ROE is determined. A consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' forward-looking views of financial markets in general, and the subject company (in the context of the proxy group) in particular.

No financial model can exactly pinpoint the correct ROE; rather, each test brings its own perspective and set of inputs that inform the estimate. Consistent with the *Hope* standard, it is

[42] National Energy Board, Reasons for Decision, TQM RH-1-2008 (March 2009), at 66-72; Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at 23; and English translation of Régie de l'energie, Decision 2009-156 (R-3690-2009), Gaz Metro, December 7, 2009, at paragraph [249].

"the result reached, not the method employed, which is controlling."[43] Although each model brings a different perspective and adds depth to the analysis, each model also has its own inherent limitations and should not be relied upon individually without corroboration from other approaches. Regardless of which analyses are used to estimate the investor-required ROE, analysts must apply informed judgment to assess the reasonableness of results and to determine the appropriate weighting to apply to results under prevailing capital market conditions.

The Board has acknowledged the need to use multiple methodologies in determining a fair return on equity for Newfoundland Power, stating:

> *The Board notes that both Mr. Coyne and Dr. Booth used a combination of methodologies, primarily founded in the CAPM and DCF approaches, to arrive at a recommended return on equity in this proceeding. This is consistent with the Board's approach in Order No. P.U. 13(2013), in which the Board found that, given the financial and economic conditions at the time, the simple application of the CAPM model could not be relied upon to produce a fair return for Newfoundland Power. Instead the Board found that a broader view and assessment of other information in relation to fair return was necessary.*[44]

For these reasons, in the 2016 Order,[45] the Board determined that "primary weighting should be given to CAPM results but also looked to the results of other accepted models and other relevant evidence when determining the fair return."

The BCUC's recent Order in the GCOC proceeding also favored the use of multiple methodologies to establish the authorized ROE. In particular, the BCUC's ROE determinations for FortisBC Energy, Inc. and FortisBC, Inc. were based on the average results of three models: 1) the Multi-Stage DCF model; 2) the CAPM using an average of the forward-looking and the historical market risk premium; and 3) the Risk Premium model based on authorized returns for U.S. electric and gas utilities since 1992.[46]

[43] See Hope Natural Gas v. Federal Power Commission.
[44] Order No. P.U. 18(2016), at 27.
[45] Ibid.
[46] British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 1), Order G-236-23, September 5, 2023, at 117-118.

A. Discounted Cash Flow ("DCF") Model

The premise underlying the DCF model is that investors value a given investment according to the present value of its expected cash flows over time. The standard DCF model is shown in Formula [1]:

$$P = \frac{D_0(1+g)^1}{(1+r)^1} + \frac{D_1(1+g)^2}{(1+r)^2} + \cdots + \frac{D_{n-1}(1+g)^n}{(1+r)^n} \qquad [1]$$

where:

P = the current stock price
g = the dividend growth rate
D_n = the dividend in year n
r = the cost of common equity.

Assuming a constant growth rate in dividends, the model may be rearranged to compute the ROE, as shown in Formula [2]:

$$r = \frac{D}{P} + \text{g} \qquad [2]$$

Stated otherwise, the cost of common equity is equal to the dividend yield plus the expected dividend growth rate.

1. Constant Growth DCF Model Assumptions

The Constant Growth DCF model requires the following assumptions: (1) a constant average growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate. As discussed later in the report, other forms of the DCF model do not rely on the assumption of constant growth in perpetuity.

2. Dividend Yield

As shown in equation [3], the dividend yield component of the DCF model is calculated as follows:

$$[3] \quad Y = \frac{D_0(1+0.5g)^1}{P_0}$$

One half year's growth rate is applied to the annual dividend rate to account for increases in quarterly dividends at different times throughout the year. It is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. This adjustment ensures that the expected dividend yield is, on average, representative of the coming twelve-month period and does not overstate the aggregated dividends to be paid during that time.

The dividend yields were calculated for each company in the respective proxy groups by dividing the current annualized dividend by the average stock price for each company for the 90 trading days ended August 31, 2023. Those dividend yields are multiplied by one-half the growth rate to reflect expected future dividend increases.

3. Growth Rate Estimates

In considering the appropriate growth rate for the DCF model, the most relied upon indicator of investors' expectations is analysts' estimates of future earnings growth. We have relied on earnings growth estimates from S&P Capital IQ (formerly SNL Financial), Value Line, Zacks Investment Research and Thomson First Call (as published on Yahoo! Finance) for the companies in the respective proxy groups. Those growth rates are shown in Exhibit JMC-4.

Investors typically rely on projected earnings growth rates rather than dividend growth rates for several reasons. First, although the DCF model is based on dividend growth rates, a company's dividend growth is derived from and can only be sustained by earnings growth. Second, in order to reduce the long-term growth rate to a single measure, as required in the Constant Growth DCF model, it is necessary to assume a constant payout ratio, and that earnings per share, dividends per share and book value per share grow at a constant rate. Third, earnings growth rates are less influenced by dividend decisions that companies may make in response to near-term changes in the business environment. Finally, analysts' forecasts of earnings growth are widely available, whereas dividend and book value growth rates are generally available only from Value Line.[47]

Some utility regulators have expressed concern that analysts' earnings growth rates may be overly optimistic. If optimism bias were present in analysts' earnings forecasts, it could create an upward bias in the estimated cost of capital that results from the DCF approach. However, financial regulators implemented several changes more than 20 years ago that were designed to provide fair disclosure and to reduce or eliminate the possibility of analysts' bias. For example, on August 15, 2000, the U.S. Securities and Exchange Commission ("SEC") adopted Regulation Fair Disclosure ("Regulation FD") to address the selective disclosure of information by publicly-traded companies. Regulation FD provides that when an issuer discloses material nonpublic information, the issuer must publicly disclose that information to all investors at the same time. In this way, the rule aims to promote full and fair disclosure.

Also, in 2002 the SEC, the New York Stock Exchange, the New York Attorney General, and other state regulators introduced guidelines regarding the interaction between analysts and investment banks that became known as the "Global Settlement." The Global Settlement outlined several structural reforms that limit the interaction between analysts and investment banks, thus removing any incentive for analysts to produce upwardly-biased growth forecasts.

In Canada, regulators took a parallel set of actions, with Policy 11 as the core framework. On April 12, 2001, the Securities Industry Committee on Analyst Standards released a draft report containing recommendations aimed at improving the independence of research and ensuring the professional practice of Canadian securities industry analysts. The Investment Dealers Association published the initial proposed Policy 11 on July 5, 2002, a revised version on April 25, 2003, and a summary of comments on August 8, 2003. Policy 11 requires more disclosures from analysts and independence of research departments. Also, in a letter dated August 15, 2002, the Ontario Securities Commission ("OSC") requested information from financial institutions about current practices to address conflicts of interest relating to equity analysts. Accordingly, in September 2002, most financial institutions had adjusted their practice and replied to OSC.

[47] Value Line is the only publication of which I am aware that projects dividend and book value growth rates. Those estimates represent the Value Line analyst's perspective on dividend and book value growth. In contrast, many of the earnings growth rates that are publicly available are consensus estimates with contributions provided by several analysts.

A 2010 article in Financial Analyst Journal found that analyst forecast bias had declined significantly or disappeared entirely since the Global Settlement:

> *Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that or related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible,* ***forecast bias clearly declined around the time the Global Settlement was announced****. These results suggest that the recent efforts of regulators have helped neutralize analysts' conflicts of interest.*[48]

Some analysts in regulatory proceedings have argued that GDP growth should serve as a limit on long-term utility earnings growth. In order to assess whether earnings growth rates are reasonable relative to GDP growth, Concentric compared the actual earnings and dividends per share growth rates for the companies in the three proxy groups for which the required data are available to GDP growth. These results are shown in Figure 22.

Figure 22: Utility Earnings, Dividend and GDP Growth Comparisons

	[1] Median EPS Growth, Historical 2008-2022	[2] Median DPS Growth, Historical 2008-2022	[3] Nominal GDP Growth CAGR, 2008-2022	[4] Median Five-Year EPS Growth Forecast	[5] Nominal Long-Term GDP Growth Forecast
Canadian Proxy Group	7.45%	10.02%	5.07%	4.75%	4.04%
U.S. Electric Proxy Group	5.04%	4.65%	3.97%	5.70%	4.14%
North American Electric Proxy Group	5.11%	4.82%	4.73%	5.68%	4.10%
Average	5.87%	6.50%	4.59%	5.37%	4.09%

[1] Value Line, median compound annual growth rate in EPS of each company in the proxy group
[2] Value Line, median compound annual growth rate in DPS of each company in the proxy group
[3] Statistics Canada and Bureau of Economic Analysis, nominal GDP Growth
[4] See Exhibit JMC-4 Constant DCF
[5] See Exhibit JMC-5 Multi-Stage DCF

48 Armen Hovakimian and Ekkachai Saenyasiri, *Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation*, Financial Analysts Journal, Volume 66, Number 4, July/August 2010, at 105. [Emphasis added.]

This analysis shows important relationships based on the most recent 15 years of history, which is a sufficient time-period to draw meaningful conclusions and to frame reasonable expectations for the future.

- Historically, dividends have tracked reasonably well with earnings growth, as would be expected, as earnings drive dividend growth. The exception is the Canadian proxy group, where dividends outpaced earnings growth over this period. This is primarily due to Enbridge, which had a significant increase in its payout ratio. We conclude that earnings growth is a reasonable proxy for dividend growth, especially with a broad enough company sample.
- Both earnings and dividend growth exceeded GDP growth by a wide margin, with the exception of DPS growth for the North American Electric proxy group, where the two measures are approximately equal. This should not be a surprise, as earnings for a healthy and well-managed utility can exceed the growth of the overall economy. There is no fundamental basis to assume that economy-wide GDP growth with a mix of macroeconomic, social, and business drivers serves as a limit on utility earnings growth.
- Looking to the future, it is not unreasonable to rely on analyst projections, as we and other experts commonly do, just because they exceed GDP growth. In fact, over the historical period, dividend growth for the three utility groups exceeded historical GDP growth by 1.91 percent. Further, the median analyst earnings growth projection of 5.37 percent is lower than the historical earnings growth rate of 5.87 percent by 0.50 percent.

These relationships indicate the projected analyst growth rates are entirely reasonable by historical standards.

4. Multi-Stage DCF Model

In order to address some of the limiting assumptions underlying the Constant Growth form of the DCF model, we also considered the results of a multi-period (three-stage) DCF Model. The Multi-stage DCF model tempers the assumption of constant growth in perpetuity with a three-stage approach based on near-term, transitional, and long-term growth rates.

The Multi-stage DCF model transitions from near-term growth (i.e., the average of Value Line, Zacks, S&P Capital IQ and First Call forecasts used in the Constant Growth model) in the first stage (years 1-5) to the long-term forecast of nominal GDP growth in the third stage (year 11 to 200). The second, or transitional, stage connects near-term growth with long-term growth by changing the growth rate each year on a pro rata basis. In the terminal stage, the dividend cash flow then grows in perpetuity at the same rate as nominal GDP. The return on equity is the internal rate of return based on the current price and this stream of dividend payments. As we have shown above, nominal GDP growth is conservative based on the historic earnings and dividend growth of the proxy group companies.

Nominal GDP growth rates for the proxy groups were developed using data for each country as reported by Consensus Economics, Inc. for the period from 2029-2033. These forecasts are based on real (constant dollar) growth rates and estimates for inflation. The inflation estimate was applied to the estimate of real GDP growth to develop the nominal (post-inflation) GDP growth rate. The estimates of nominal GDP growth are summarized in Figure 23.

Figure 23: Estimates of Nominal GDP Growth[49]

Source	Canada	U.S.
Real GDP Growth	1.9%	1.8%
Inflation	2.1%	2.3%
Nominal GDP Growth	**4.04%**	**4.14%**

49 Consensus Forecasts, Survey Date April 11, 2023, at 3 (U.S.) and 28 (Canada).

5. DCF Results

The DCF results are shown in Exhibits JMC-4 and JMC-5. As summarized in Figure 24, the DCF analyses produce cost of equity estimates ranging from 9.38 to 10.44 percent and an overall average of 9.7 percent for the North American Electric Utility proxy group, including an adjustment for flotation costs and financial flexibility.

Figure 24: 90-day Average DCF Results (including adjustment for flotation costs and financial flexibility)

Proxy Group	Constant Growth	Multi-Stage	Average
Canadian Utility	10.03%	10.18%	10.1%
U.S. Electric Utility	10.44%	9.38%	9.9%
North American Electric Utility	10.07%	9.42%	9.7%

As discussed in more detail in Section VI, the North American Electric Utility proxy group is more comparable to Newfoundland Power than the Canadian utility proxy group companies, several of which have significant non-electric operations and unregulated operations. Conversely, the U.S. Electric utility proxy group is comprised of companies that derive almost 100 percent of net operating income and operating revenues from electric utility operations and dedicate almost 100 percent of assets to regulated electric utility service. In addition, a September 2013 Moody's report indicated that the regulatory environment for utilities in the U.S. is more favorable than the rating agency previously believed, primarily due to the increased use of cost recovery mechanisms and reduced regulatory lag in the U.S. Moody's stated:

> *Based on our observations of trends and events, we propose to adopt a generally more favorable view of the relative credit supportiveness of the US utility regulatory environment. Our updated view considers improving regulatory trends that include the increased prevalence of automatic cost recovery provisions, reduced regulatory lag, and generally fair and open relationships between utilities and regulators.*[50]

50 Moody's Investors Service, "Proposed Refinements to the Regulated Utilities Rating Methodology and Our Evolving View of U.S. Utility Regulation," September 23, 2013, at 1.

On that basis, in February 2014 Moody's upgraded the credit ratings of many U.S. utilities. Finally, the BCUC's September 2023 Order in the GCOC proceeding relied on the results of a North American proxy group that included both Canadian and U.S. companies, and no adjustment was made to the U.S. data for differences in risk between the two countries.

B. Capital Asset Pricing Model ("CAPM")

The CAPM method is based on the relationship between the required return of a security and the systematic risk of that security. As shown in Equation [4], the CAPM is defined by four components, each of which must be a forward-looking estimate:

[4] $Ke = rf + \beta(rm - rf)$

where:

Ke = the required ROE for a given security;

β = Beta of an individual security;

rf = the risk-free rate of return; and

rm = the required return for the market as a whole.

The term $(rm - rf)$ represents the Market Risk Premium ("MRP"). According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

[5] $$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)}$$

where:

re = the rate of return for the individual security or portfolio.

The variance of the market return, noted in Equation [5], is a measure of the variability in the general market, and the covariance between the return on a specific security and the market reflects the extent to which the return on that security will respond to a given change in the market return. Thus, Beta represents the risk of the security relative to the market.

1. Risk Free Rate

Bond yields have increased substantially after reaching historic lows in 2020, as higher inflation has caused bond market participants to require higher yields. Although current interest rates on Canadian government bonds are 156 to 215 basis points higher than in March 2021, we have continued to use a forecast bond yield as the risk-free rate because the cost of equity is forward-looking. Forecast bond yields reflect the market reality that while current bond yields have increased substantially, investors are factoring somewhat lower interest rates into their longer-term expectations and required returns.

Our CAPM analysis relies on the 2024 through 2026 average *Consensus Economics* forecast of the Canadian 10-year government bond (shown in Figure 25) plus the historical spread between 10-year and 30-year government debt.

Figure 25: Long-term Forecast for 10-Year Government Bond Yields 2024-2026[51]

	2024	2025	2026	Average
Canada	3.0%	3.2%	3.2%	**3.13%**
U.S.	3.5%	3.4%	3.4%	**3.43%**

With an average spread between 10-year and 30-year government bond yields of 38 basis points in Canada and 54 basis points in the U.S.,[52] the corresponding longer-term yield on 30-year government bonds over the period 2024 – 2026 is shown in Figure 26.

Figure 26: Risk Free Rate

30-Year Risk Free Yield	Canada	U.S.
April 2023 Consensus Forecast Average 2024-2026 Forecasts	3.13%	3.43%
Average Daily Spread between 10-year and 30-year government bonds (2013-2023)	0.38%	0.54%
Sum	**3.52%**	**3.98%**

[51] Consensus Forecasts by Consensus Economics Inc., Survey Date April 11, 2023, at 28 and 3.
[52] Historical spreads were calculated using daily bond yields for the 10-year period from September 1, 2013, and August 31, 2023. All values are rounded to two decimal places.

In light of current 30-year bond yields (5.05% in the U.S. and 3.88% in Canada as of October 26, 2023) these forecasts seem conservative on the low side.

2. Beta

We have measured the beta coefficients for the Canadian and U.S. proxy groups using estimates from both Value Line and Bloomberg. Value Line publishes the historical beta for each company based on five years of weekly stock returns and uses the New York Stock Exchange as the market index. Bloomberg produces beta estimates based on parameters entered by the user. We have computed Bloomberg betas based on five years of weekly stock returns and using the S&P 500 or the S&P/TSX Composite as the market index. Value Line reports adjusted betas to compensate for the tendency of beta to revert toward the market average of 1.0 over time, and we have used adjusted betas from Bloomberg over a five-year period for consistency. The betas used in our CAPM analyses are shown in Figure 27.

Figure 27: Value Line and Bloomberg Betas

	Value Line	Bloomberg
Canadian Group	0.78	0.87
U.S. Electric Utility Group	0.89	0.89
North American Electric Group	0.87	0.86

There are two primary reasons to adjust raw betas. First, empirical studies have provided evidence that an individual company beta is more likely than not to move toward the market average of 1.0 over time. Second, adjusting beta serves a statistical purpose. Because betas are statistically estimated and have associated error terms, betas greater than 1.0 tend to have positive estimated errors and thus tend to overestimate future returns. Betas below the market average of 1.0 tend to have negative error terms and underestimate future returns. Consequently, it is necessary to adjust forecasted betas toward 1.0 in an effort to improve the accuracy of forecasts.[53] Furthermore, with utility betas increasing substantially over the course of the past three years, the effect of the standard Blume adjustment is lessened by the increase in the raw beta.

[53] Roger A. Morin, *New Regulatory Finance*, at 74.

Because current stock prices reflect expected risk, one must use an expected beta to appropriately reflect investors' expectations. A raw beta reflects only where the stock price has been relative to the market historically and is an inferior proxy for the expected returns when compared to the adjusted beta. Some have argued, particularly in Canada, that raw betas or some other (lesser) adjustment to utility betas is appropriate. An expert took this position in the 2022/2023 GRA proceeding for Newfoundland Power.[54] The common approach, however, is to employ the widely utilized Blume adjusted betas.

Dr. Marshall Blume specifically studied four groups of betas, ranging from a very low beta group (averaging 0.50, and similar to the utility industry) to a very high beta group, and he found that his adjustment best predicted future betas for each of the four risk groups over the next seven years. Dr. Blume found that a low beta portfolio that averaged 0.50 migrated towards the grand mean of all betas of 1.0 approximately in accordance with the Blume formula. The study makes obvious that betas migrate towards 1.0 and do indeed exceed their long-term unadjusted averages. Given that the purpose of estimating the CAPM relying on these beta coefficients is to estimate the forward-looking cost of capital, it is important to reflect a forward view of beta and its tendency to migrate towards the market mean over time, which is not limited to the long term historic average of the industry beta.

In its September 2023 Order in the GCOC proceeding, the BCUC accepted the use of Blume adjusted betas in the CAPM analysis, noting that this was a departure from its previous decisions on the issue in 2013 and 2016. The BCUC retained Dr. Jonathan A. Lesser to provide expert advice on the appropriate methodologies and inputs to be used in each model. Dr. Lesser also supported the use of Blume adjusted betas. Specifically, the BCUC stated:

> *The Panel notes Mr. Coyne's explanation that Dr. Blume found that his adjustment was applicable to all betas, ranging from a low of 0.50 to a high of 1.53, and in Mr. Coyne's view, there is no reason to expect that regulated utilities would be an exception to this rule. Given the views of the two experts in this proceeding and since none of the parties object to Mr. Coyne's use of Blume-adjusted data, the Panel accepts the experts' recommendation to use the Blume-adjusted beta estimates for the proxy groups.*[55]

[54] Evidence of Laurence D. Booth, September 28, 2021, at 61-62.
[55] British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 1), Order G-236-23, September 5, 2023, at 75.

We agree with Dr. Lesser, and in Concentric's experience these are the commonly employed sources of Beta for cost of capital analysis.

3. Market Risk Premium ("MRP")

Estimates of the MRP generally fall into two categories, *ex-post* (historical arithmetic average) and *ex-ante* (forward looking). The historical MRP is based on the arithmetic mean of the equity market returns over the income-only return on long-term government bonds, based on data from Kroll (formerly Duff & Phelps) since 1919 in Canada and since 1926 in the U.S. The forward-looking MRP is calculated by subtracting the risk-free rate for each country from the estimated total return for the overall market, as calculated using the DCF methodology for the S&P/TSX Composite Index in Canada and the S&P 500 Index in the U.S.

Because the U.S. and Canadian economies are highly integrated and capital flows freely across the border, the risk premiums for each country are highly correlated. Accordingly, it is reasonable to derive a single estimate of the MRP for Canada and the U.S., as shown in Figure 28. See Exhibits JMC-6 and JMC-7 for the derivation of the forward-looking MRP for Canada and the U.S.

Figure 28: Market Risk Premia – Canada and U.S.

	Canadian MRP	U.S. MRP
Historical	5.62%	7.17%
Forward-Looking	4.85%	10.33%
Average	6.99%	

The BCUC's September 2023 GCOC decision supported use of an equal weighting of the historical and forward-looking MRP for Canada and the U.S., with the forward MRP estimated using a DCF analysis of the companies in the S&P/TSX and S&P 500 indices.[56]

Although we have presented an average of the historical and forward-looking MRP, we rely on the CAPM results using only a historical MRP in order to temper the results of our CAPM analysis.

[56] British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 1), Order G-236-23, September 5, 2023, at 84-85.

4. CAPM Results

The results of the CAPM analysis, including an adjustment for flotation costs and financial flexibility, are provided in Figure 29 and in Exhibit JMC-8.

Figure 29: CAPM Results

	Average MRP	Historical MRP
Canadian Utilities	10.09%	9.57%
U.S. Electric Utilities	10.68%	10.15%
North American Electric Utilities	10.37%	9.86%

C. Flotation Costs and Financing Flexibility

It is common practice for Canadian regulators to approve an adjustment for flotation costs and financing flexibility. The Board has previously determined that it is appropriate to add an allowance for flotation costs and financing flexibility of 0.50 percent to the allowed equity return.[57] This adjustment for flotation costs and financial flexibility compensates the equity holder for the costs associated with the sale of new issues of common equity, and it also provides the financial strength needed to attract capital under a variety of economic and financial market conditions. These costs include out-of-pocket expenditures for the preparation, filing, underwriting and other costs of issuance of common equity including the costs of financial flexibility such that there is adequate cushion to raise equity in challenging capital market conditions. Because the purpose of the allowed rate of return in a regulatory proceeding is to estimate the cost of capital the regulated company would incur to raise money in the "primary" markets, an estimate of the returns required by investors in the "secondary" markets must be adjusted for flotation costs in order to provide an estimate of the cost of capital that the regulated company requires. We have adjusted the DCF and CAPM results upwards by 50 basis points for flotation costs and financing flexibility.

[57] In Order No. P.U. 18(2016), the Board did not explicitly accept/reject flotation costs but did note that the CAPM results include a 50 bps adjustment.

D. Risk Premium Analysis

In general terms, the Risk Premium approach recognizes that equity is riskier than debt because equity investors bear the residual risk associated with ownership. Equity investors, therefore, require a greater return (i.e., a premium) than would a bondholder. The Risk Premium approach estimates the cost of equity as the sum of the Equity Risk Premium and the yield on a particular class of bonds.

$$ROE = RP + Y \quad [6]$$

Where:

RP = Risk Premium (difference between allowed ROE and the 30-Year Treasury Yield) and
Y = Applicable bond yield.

Since the equity risk premium is not directly observable, it is typically estimated using a variety of approaches, some of which incorporate ex-ante, or forward-looking, estimates of the cost of equity and others that consider historical, or ex-post, estimates. For our Risk Premium analysis, we have relied on authorized returns from a large sample of U.S. electric utility companies. It is necessary to conduct the Risk Premium analysis based on authorized returns for U.S. electric utility companies because there are not a sufficient number of Canadian ROE decisions to develop a statistically-meaningful regression analysis.

To estimate the relationship between risk premia and interest rates, we conducted a regression analysis using the following equation:

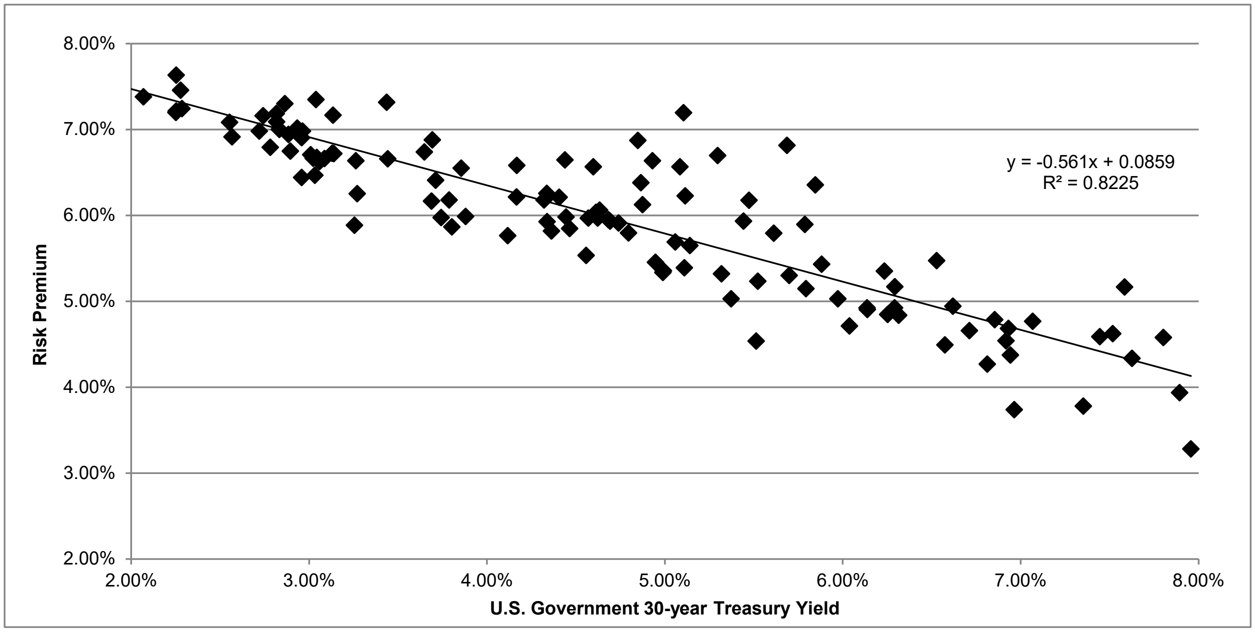
$$RP = a + (b \times Y) \quad [7]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the 30-Year Treasury Yield);
a = Intercept term;
b = Slope term; and
Y = 30-Year Treasury Yield.

Data regarding allowed ROEs were derived from 717 integrated electric utility company rate cases in the U.S. from January 1992 through August 31, 2023, as reported by Regulatory Research Associates.

Figure 30: Risk Premium Results



As illustrated in Figure 30, the risk premium varies with the level of the bond yield, and generally increases as the bond yields decrease, and vice versa. In order to apply this relationship to current and expected bond yields, we consider three estimates of the 30-year Treasury yield, including the current 30-day average, a near-term consensus forecast for Q4 2023 – Q4 2024, and a long-term consensus forecast for 2025–2029. We find this 5-year result to be most applicable because investors typically have a multi-year view of their required returns on equity. Based on the regression coefficients in Exhibit JMC-9, which allow for the estimation of the risk premium at varying bond yields, the results of our Risk Premium analysis are shown in Figure 31.

The BCUC recently included the results of the Risk Premium model based on an analysis of the risk premium indicated by authorized ROEs for U.S. gas and electric utilities over the corresponding yield on U.S. government bonds. The BCUC gave the Risk Premium analysis equal weighting with the Multi-Stage DCF model and the CAPM in establishing the authorized ROE for FortisBC Energy, Inc. and FortisBC, Inc. Specifically, the BCUC stated that "considerable weight should be given to the use of a Risk Premium Model for the purposes of determining the appropriate ROE for FEI and FBC given the volatility in the market and economic conditions," and that "the strengths of the Risk Premium Model outweigh its shortcomings."[58]

Figure 31: Risk Premium Results Using 30-Year Treasury Yield

	Using 30-Day Average Yield on 30-Year Treasury Bond	Using Q4 2023–Q4 2024 Forecast for Yield on 30-Year Treasury Bond[59]	Using 2025-2029 Forecast for Yield 30-Year Treasury Bond[60]
Yield	4.21%	4.04%	3.80%
Risk Premium	6.23%	6.33%	6.46%
Resulting ROE	10.44%	10.37%	10.26%

58 British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 1), Order G-236-23, September 5, 2023, at 117-118.

59 Blue Chip Financial Forecasts, Vol. 42, No. 7, July 1, 2023, at 2.

60 Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023, at 14. The bond yield forecast shown in Figure 26 is based on information from Consensus Economics and is somewhat higher than the Blue Chip forecast used in the Risk Premium analysis.

E. Comparison to Other Authorized ROEs

Regulators also consider authorized ROEs and common equity ratios for other investor-owned electric utilities in Canada and the U.S. when setting allowed returns. Given the "opportunity cost" concept underlying a fair return, this is appropriate, as an investor would shift capital to a higher return for the same level of risk, if available. As shown in Figure 32, the average allowed ROE for Canadian investor-owned electric utilities in 2023 is approximately 9.17 percent, while in the U.S., the average allowed ROE for electric utilities from January 2022 through September 2023 was 9.66 percent. Notably, the formula-based ROE in Ontario increased from 8.66 percent for 2022 to 9.36 percent for 2023 for all regulated utilities operating under the formula, reflecting higher interest rates on government and corporate bonds.[61]

Figure 32: Authorized Electric ROEs

Newfoundland Power (existing)	8.50%
Newfoundland Power (proposed)	9.85%
Nova Scotia Power	9.00%
Maritime Electric Company Ltd	9.35%
Ontario Electric Utilities	9.36%
Alberta Electric Utilities[62]	8.50%
FortisBC Inc.	9.65%
Canadian Electric Average	**9.17%**
U.S. Electric Utilities[63]	**9.66%**

[61] Ontario Energy Board, Cost of Capital Parameter Updates for 2023 Cost of Service and Custom Incentive Rate-setting Applications, issued October 20, 2022.

[62] In Decision 27084-D02-2023, the Alberta Utilities Commission established a notional ROE for electric and gas utilities of 9.0 percent. This value is to be adjusted using the AUC's new formula to determine the authorized ROE for 2024 and subsequent years.

[63] Source: SNL Financial. Figures are from January 1, 2022 through September 25, 2023, excluding limited issue riders and electric transmission cases, and excluding decisions in Illinois and Vermont where the authorized ROE is set based on an automatic formula that adjusts with changes in government bond yields.

VI. CAPITAL STRUCTURE AND RISK ANALYSIS

A. Newfoundland Power's Deemed Equity Ratio

In Order No. P.U. 3(2022), the Board approved a settlement agreement for Newfoundland Power's 2022/2023 GRA which included a deemed common equity ratio for Newfoundland Power at 45 percent. In particular, the Board observed that "Newfoundland Power has maintained a solid financial profile and investment grade credit rating… and this has contributed to its continued access to capital markets on reasonable terms"[64] and that "both Moody's and DBRS recognize Newfoundland Power's longstanding 45% common equity component of its capital structure as a key credit strength."[65] This determination is consistent with the Board's 2016 decision when it cited the following factors:

a) Newfoundland Power's small size relative to its peers has been identified by the Board in the past as supporting a 45% common equity ratio.[66]

b) Moody's cites the higher deemed equity level of 45% as a factor which mitigates against the lower return on equity historically allowed by the Board compared to other Canadian utilities. The Board accepts that there is a cost to maintaining the higher common equity ratio. However, there may also be a cost to reducing the equity ratio in terms of required borrowings, potential credit metric impacts and increased financial risk…[67]

c) The Board is not satisfied that the evidence supports a decrease in the common equity component at this time. As noted by Newfoundland Power, the Court of Appeal has alluded to the importance of stability in the management of capital structure for a utility.[68]

Based on these considerations, the Board concluded:

> *In the circumstances the Board does not believe it is appropriate to deem a reduced common equity ratio for Newfoundland Power given the uncertainty associated with Muskrat Falls and the economic outlook for the province and also in light of the concerns*

64 Order No. P.U. 3(2022), at 5.
65 Ibid.
66 Order No. P.U. 18(2016), at 24.
67 Ibid.
68 Ibid.

> *set out by Newfoundland Power in relation to the issuance or deeming of preferred shares. The Board is concerned about the impact of such a change on Newfoundland Power's credit metrics and how this would be viewed by the markets. The Board believes that the circumstances require a conservative and stable regulatory approach and therefore Newfoundland Power's deemed common equity ratio will not be lowered at this time.*[69]

In 1999, the Board explained the rationale for its decision supporting the 45 percent deemed common equity ratio as follows: "The Board believes that in order to maintain an "A" rating and appropriate access to capital markets, as a small utility, NLP will require a stable and strong capital structure."[70] In particular, the Board observed that Newfoundland Power's smaller size reduces the Company's financial flexibility.[71] That factor was again cited in the 2016 Order.[72]

B. Risk Analysis

Concentric examines risk from two primary perspectives: (1) financial risk; and (2) business risk. Financial risk primarily relates to the risk associated with the way in which a company finances its business, as evidenced by the relative percentages of debt and equity in the capital structure. To the extent the company is more highly leveraged, it requires higher net income to cover its fixed interest obligations, which must be paid before there is any net income for shareholders. Business risk for a regulated utility encompasses both operational risk (e.g., economy of service territory, weather conditions, geographical diversity, etc.) and regulatory risk (e.g., opportunity for timely recovery of prudently incurred costs). Taken together, financial risk and business risk are the primary elements of investment risk that investors consider when establishing their return requirements.

In each risk category, Concentric further considers three perspectives:

a) Comparison of the risk profile of Newfoundland Power to other investor-owned electric utilities in Canada to determine if the Company continues to be an average risk Canadian utility;

[69] Ibid, at 25.
[70] Order No. P.U. 16(1998-99), at 58.
[71] Order No. P.U. 16(1998-99), at 37.
[72] Order No. P.U. 18(2016), at 24.

b) Comparison of the current risk profile of Newfoundland Power to a proxy group of comparable electric utilities in the U.S.; and

c) Comparison of Newfoundland Power's risk profile today to the circumstances at the time of the Company's 2022/2023 GRA filing.

1. Financial Risk

a. Definition of Financial Risk

Financial risk exists to the extent a company incurs debt obligations in financing its operations. These fixed obligations increase the level of income which must be generated to cover interest payments before common stockholders receive any return, and they are considered by both debt and equity investors in addition to business risks. Fixed financial obligations also reduce a company's financial flexibility and its ability to respond to adverse economic circumstances and capital market conditions, such as those during the credit crisis and financial market disruptions of 2008 and 2009, and more recently during the COVID-19 induced disruption in financial markets.

b. Implication of Capital Structure on Rate of Return

The capital structure relates to a company's financial risk, which represents the risk that a company may not have adequate cash flows to meet its financial obligations and is a function of the percentage of debt (or financial leverage) in the capital structure. The Board has observed the relationship between rates of return and capital structure in previous decisions, stating: "The inter-relationship between rates of return and capital structure is quite strong and, therefore, selecting a point within a range for capital structure is a critical component of the decision for all parties."[73] Moreover, the Board has stated: "However, the higher the debt as a proportion of total capital, the greater the risk to shareholders. Debtors rank ahead of shareholders for cash flow and in the event of liquidation."[74] In that regard, as the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt. Consequently, as the degree of financial leverage increases, the risk of financial distress for common equity holders (i.e.,

[73] Order No. P.U. 16 (1998-99), at 47.
[74] Ibid, at 49.

financial risk) also increases.[75] Since the capital structure can affect the company's overall level of risk, it is an important consideration in establishing a fair return.

c. Comparison to Other Investor-Owned Utilities

As explained in Section IV, we have selected three proxy groups consisting of Canadian, U.S. Electric, and North American Electric utilities for purposes of establishing our ROE recommendation for Newfoundland Power. In order to assess the reasonableness of the common equity ratio for Newfoundland Power, our analysis is based on a comparison to the equity ratios of other investor-owned electric utilities in Canada and the U.S. at the operating company level because that is the level at which a regulated capital structure is established based on an evaluation of the business risk of the utility and related factors.

As shown in Figure 33, Newfoundland Power's deemed common equity ratio of 45 percent is higher than the five other Canadian investor-owned electric operating utilities. The average authorized common equity ratio for U.S. electric utilities from January 2022 through August 2023 was 51.6 percent, or 6.6 percent points higher than Newfoundland Power's current deemed common equity ratio of 45 percent.

Figure 33: Comparison of Allowed Equity Ratios and Authorized ROEs

Operating Utility	Deemed Equity Ratio	Authorized ROE
Newfoundland Power (existing)	45.0%	8.50%
Newfoundland Power (proposed)	45.0%	9.85%
Alberta Electric Utilities[76]	37.0%	8.50%
FortisBC Electric	41.0%	9.65%
Ontario Electric Utilities	40.0%	9.36%
Maritime Electric	40.0%	9.35%
Nova Scotia Power	40.0%	9.00%
Canadian Electric Average	**39.6%**	**9.17%**
US Electric Utility Average[77]	**51.6%**	**9.66%**

75 See Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 45-46.

76 In Decision 27084-D02-2023, the Alberta Utilities Commission established a notional ROE for electric and gas utilities of 9.0 percent. This value is to be adjusted using the AUC's new formula to determine the authorized ROE for 2024 and subsequent years.

77 S&P Global Market Intelligence, based on electric rate case decisions from January 1, 2022 through September 25, 2023, excluding decisions in Arkansas, Florida, Indiana and Michigan where the equity ratio includes zero cost items (such as accumulated deferred income taxes) that are typically excluded from rate base in other jurisdictions.

Concentric also compared Newfoundland Power's common equity ratio of 45 percent to Transmission and Distribution ("T&D") utilities of similar size in the U.S. Figure 34 presents the average allowed common equity ratio for a group of T&D utilities, most of which provide electric utility service in the northeastern U.S. Each company has 1) a rate base between $500 million and $3 billion, and 2) a rate case decision between January 2022 and September 2023. The average common equity ratio for this group of T&D utilities is 50.3 percent, reflecting higher overall equity ratios than Newfoundland Power.

Figure 34: U.S. T&D Utility Sample

Company	**Authorized Common Equity Ratio**
The United Illuminating Company	50.0%
Delmarva Power and Light (MD)	50.5%
Central Maine Power	50.0%
Versant Power	49.0%
Orange and Rockland Utilities	48.0%
Duke Energy Ohio	50.5%
Dayton Power & Light Co.	53.9%
Mean	**50.3%**

In addition, we compared Newfoundland Power's common equity ratio of 45 percent to the actual common equity ratios of the operating utility companies held by the U.S. Electric proxy group. As shown in Exhibit JMC-10, the average common equity ratio for the U.S. Electric proxy group is 52.84 percent over the past eight quarters, within a range from 45.52 percent to 61.32 percent. Newfoundland Power's common equity ratio is below the low end of the range for the U.S. Electric proxy group, indicating its greater debt leverage compared to similar companies in the U.S.

d. Assessment of Credit Metrics

Financial risk is also measured through other credit metrics, such as Cash From Operations ("CFO") to Interest, CFO to Debt, and CFO – Dividends to Debt. Exhibit JMC-11 (also summarized in Figure 35 below) shows the credit metrics for Newfoundland Power in 2022 compared to the companies in the U.S. Electric proxy group and the Canadian proxy group.

Figure 35: 2022 Moody's Credit Metrics Comparison

Credit Metric	NPI	Canadian	U.S. Electric
Debt to Capitalization	48.5%	56.0%	53.2%
CFO pre W/C + Interest / Interest	4.40	3.65	6.79
CFO pre W/C / Debt	17.4%	10.1%	15.2%
CFO pre W/C – dividends / Debt	13.2%	6.3%	10.8%

Compared to the U.S. Electric proxy group average, Newfoundland Power has a lower debt to capitalization ratio, a weaker CFO pre-Working Capital + Interest to Interest ratio, and higher ratios for CFO pre-Working Capital to Debt and CFO pre-Working Capital – Dividends to Debt. Comparison to the Canadian proxy group is limited because Emera Inc. and Hydro One Limited are the only companies in the Canadian peer group that have relevant credit metrics from Moody's. Enbridge Inc. is rated by Moody's but has different credit metrics that do not align with these categories. The other companies in the Canadian proxy group are not rated by Moody's.

Based on a comparison of the equity ratios and credit metrics of Newfoundland Power to the companies in the U.S. Electric proxy group, Concentric concludes that Newfoundland Power generally has a comparable financial risk profile in relation to the U.S. Electric proxy group based on its 2022 metrics. Newfoundland Power's credit metrics are impacted by wholesale power pricing that fluctuates year-to-year.[78] The Company's CFO pre-W/C + Interest /Interest ratio is expected to decline from 4.4 in 2022 to 3.6 in 2023 and its CFO pre-W/C / Debt ratio is expected to decline from 17.4 to 12.9. These ratios would bring Newfoundland Power closer to its Canadian peers but below its U.S. peers.

[78] The marginal cost of power that Newfoundland Power obtains from Hydro exceeds the average supply costs embedded in customer rates which, along with energy sales variances, can create fluctuations in the cash flow metrics from year-to-year. These pricing dynamics may change due to Muskrat Falls. See Moody's March 31, 2023, credit opinion for Newfoundland Power Inc. at page 5 for details.

e. Change in Newfoundland Power's Financial Risk Since 2021

Newfoundland Power's first mortgage bonds have consistently maintained credit ratings of "A" from DBRS since 1997 and "A2" from Moody's since 2009. The long-term issuer rating for Newfoundland Power from DBRS is "A" and from Moody's is "Baa1". In previous Orders, the Board has observed that "Newfoundland Power's capital structure is recognized by the credit rating agencies as a strength, which positively impacts its credit worthiness."[79] A March 2023 Moody's report reaffirmed the current ratings for Newfoundland Power, noting the supportive regulatory environment in Newfoundland and Labrador. Moody's continues to express concern, however, with respect to the effect of the Muskrat Falls hydroelectric project on electricity rates, and Moody's has further elaborated on that concern in its most recent report where it states:

> *The credit profile is negatively impacted by the risk of future cost recovery associated with the Province of Newfoundland and Labrador's sizeable Muskrat Falls hydroelectric project. This politically sensitive project is large relative to the provincial economy and may place significant upward pressure on the future electricity rates of NPI, a credit negative.*[80]

***

> *NPI faces uncertainties due to the timing and size of expected rate increases associated with the Province's Muskrat Falls hydroelectric project. The total cost of Muskrat Falls and associated transmission in Newfoundland and Labrador has increased to about CAD13.4 billion and this may increase. The size of the project and associated rate increases are exacerbated by the relatively small size of NPI. The 824 MW hydro electric project was completed in November 2021, however the Labrador Island Link (LIL) a key transmission project, is still not yet fully commissioned although it is transmitting some power. The LIL has not passed high power testing that would enable it to operate at its design capacity. The entire project, including the LIL, needs to be fully commissioned before it goes into rates.*

79 Order No. P.U. 18(2016), at 24.

80 Moody's Investors Service Global Credit Research, Credit Opinion: Newfoundland Power Inc. Update to credit analysis, March 31, 2023, at 1.

> *NL Hydro continues to work with the Province towards a rate mitigation plan that will clearly include ongoing federal government support. While NPI is allowed to pass through the increase in power supply costs to customers, the utility remains exposed to volume risk. The increase in rates from the project may lead to lower electricity demand resulting in lower revenues and cash flow.*[81]

Even though this has financial risk implications due to the potential impact on credit ratings, we consider this an operating and regulatory risk; therefore, this is covered in more detail in the section on business risk.

DBRS Morningstar has also commented that "Newfoundland Power's financial risk assessment has remained stable, with all key credit metrics supportive of the current credit ratings."[82]

f. Conclusions on Financial Risk

Newfoundland Power with its 45 percent common equity ratio has more common equity in its capital structure than the other Canadian investor-owned electric utilities and falls between the long-term issuer ratings from Moody's of Emera Inc. and Hydro One Ltd.[83]

Newfoundland Power has weaker CFO to interest coverage ratios than the U.S. Electric utility proxy group companies, and greater debt leverage, but is stronger on the two other credit metrics. Newfoundland Power's long-term issuer rating of Baa1 is the same as the U.S. Electric utility proxy group average. While credit rating agencies may be satisfied with the degree of regulatory and cash flow protection for debt investors, Newfoundland Power's weaker cash flow to interest coverage ratio exposes equity investors to somewhat greater risk than their U.S. counterparts. Overall, Newfoundland Power has a comparable financial risk profile in relation to the U.S. Electric proxy group, based on 2022 credit metrics, although the cash flow metrics fluctuate from year-to-year as discussed above.

81 Ibid, at 3.

82 DBRS Morningstar Rating Report, Newfoundland Power Inc., October 13, 2023, at 1.

83 Among proxy group companies, Newfoundland Power's Moody's credit rating of Baa1 is higher than Emera Inc. at Baa3 but lower than Hydro One Ltd. at A3. Newfoundland Power has the same Moody's rating as other electric operating utilities in Canada such as FortisBC Electric and FortisAlberta. Nova Scotia Power is also rated BBB+ by S&P, which is equivalent to Newfoundland Power's Baa1 rating from Moody's.

2. Business Risk

a. Definition of Business Risk

Business risk for a regulated utility reflects risks affecting cash flows and earnings that impact the utility's ability to recover its costs including the fair return on, and of, its capital in a timely manner. Concentric includes operating risk and regulatory risk under this broad definition of business risk.

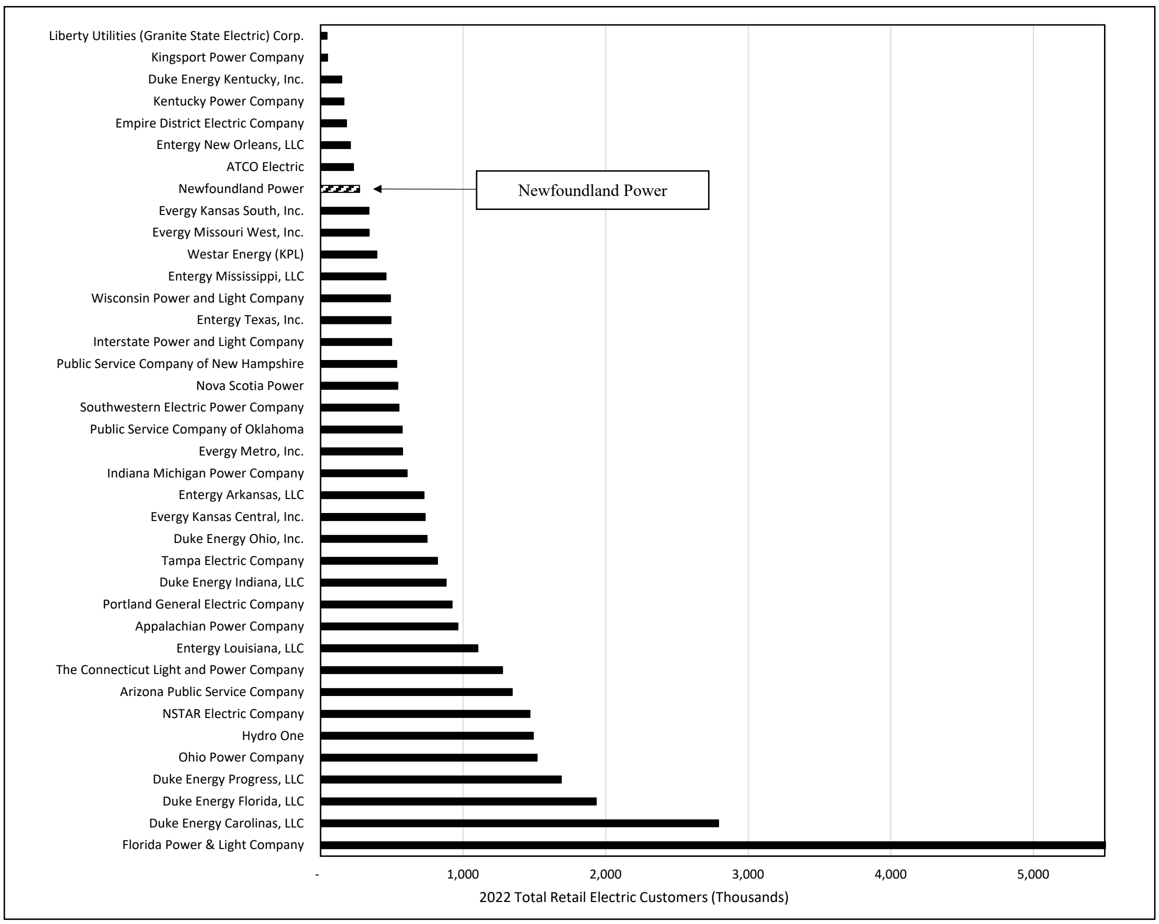
b. Business Risk Analysis

In order to assess Newfoundland Power's business risk, we examined the following factors: 1) the small size of Newfoundland Power relative to other investor-owned electric utilities; 2) macroeconomic and demographic trends in Newfoundland and Labrador; 3) operating risks associated with the Company's service territory, particularly the prevalence of severe weather conditions and the low population density of the service territory; 4) changes in the power supply of Newfoundland Power; and 5) competition from alternative fuels. Where appropriate, we have examined changes since the Company's previous 2022/2023 GRA filing.

c. Small Size

The Board has previously indicated that the small size of Newfoundland Power is one of the key factors supporting its common equity ratio of 45 percent.[84] The small size of Newfoundland Power increases the risk associated with adverse economic conditions in the province that could result in reduced demand for electricity among residential and commercial customers. Figure 36 shows that Newfoundland Power with 274,000 customers continues to have fewer retail customers than most investor-owned electric utilities in Canada and the operating companies in the U.S. Electric utility proxy group.

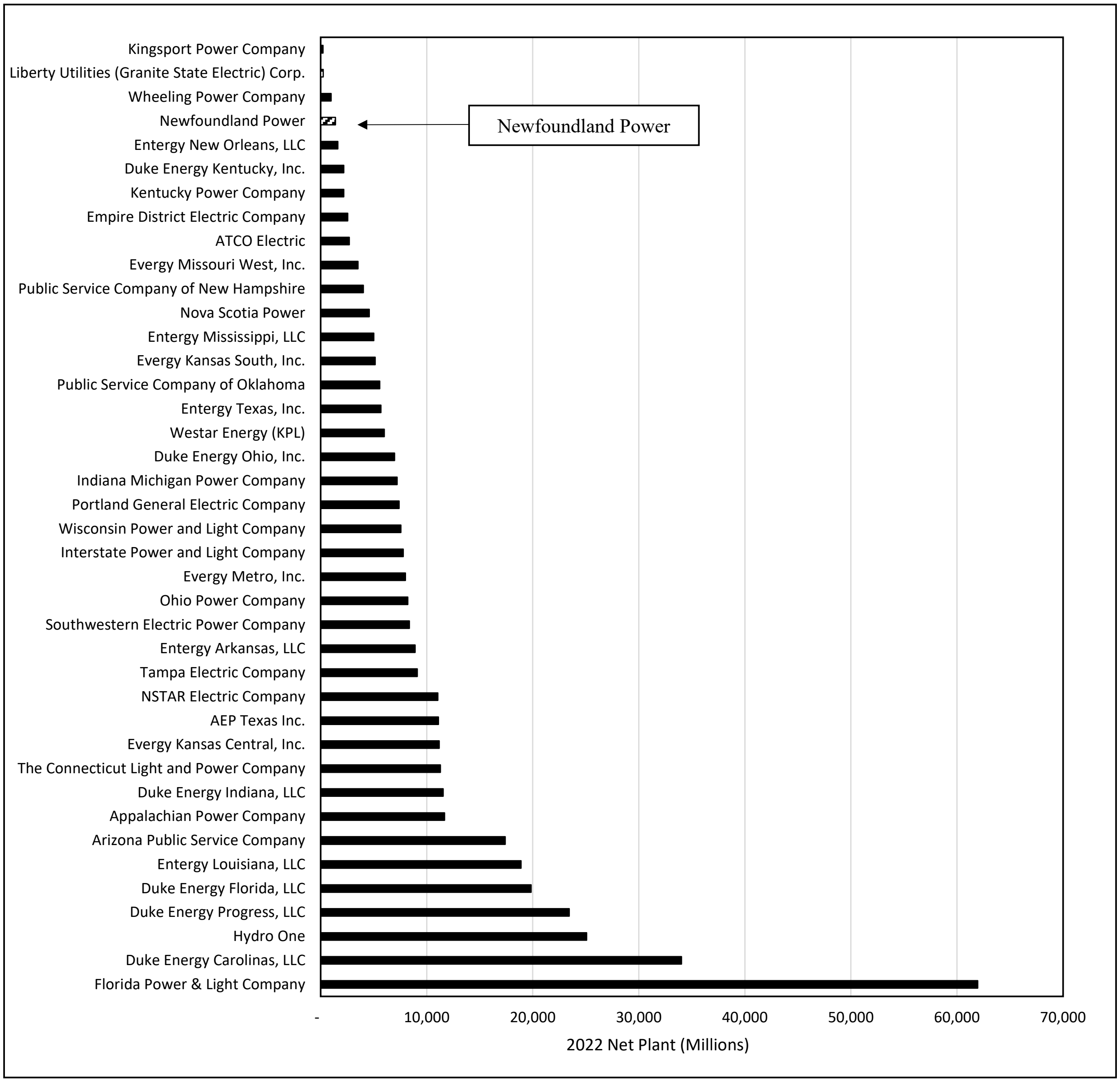
Figure 36: Small Size of Newfoundland Power 2022 Retail Electric Customers



84 Order No. P.U. 18(2016), at 24.

In terms of net property, plant and equipment, Figure 37 shows that Newfoundland Power is smaller than other investor-owned electric utilities in Canada and is substantially smaller than the electric utility operating companies in the U.S. Electric proxy group except for Kingsport Power, Granite State Electric, and Wheeling Power.

Figure 37: Small Size of Newfoundland Power 2022 Net Property, Plant and Equipment



The small size of Newfoundland Power also affects the terms of the Company's debt financing. Specifically, Newfoundland Power's debt issuances are typically in the range of $75 million to $100 million with fewer than 10 investors, while Canadian debt markets generally require a minimum issuance amount of $100 million, a minimum requirement of 10 investors, and $200 million to reach the liquid stage of the market. In 2023, Newfoundland Power issued $90 million in long-term first mortgage bonds to seven investors in a private placement. The Company's evidence discusses how the smaller size of debt issuances for Newfoundland Power contributes to liquidity constraints in placing the debt and in higher pricing differentials with long Canada bond yields.

As previously noted, the Board has recognized that the small size of Newfoundland Power limits the Company's financial flexibility and supports a higher-than-average common equity ratio. Nothing has changed in this regard since the previous GRA filing.

d. Macroeconomic and Demographic Trends

According to the Conference Board's February 2023 long-term outlook for Newfoundland and Labrador:

a) Economic growth in Newfoundland and Labrador is forecast to decelerate and average 1.0 per cent over the next two decades – much lower than the 2.3 per cent annual growth from 2000 to 2019.[85]

b) A poor demographic outlook will be the primary reason behind slow economic growth. We expect Newfoundland and Labrador's population to start dropping after the next two years and keep falling throughout the forecast period, shrinking from around 525,000 to 463,500 between 2022 and 2045 – a decline of almost 12 per cent.[86] In the near term, however, population in Newfoundland and Labrador has increased by about 5,000 due to international immigration and people moving back to the province within Canada.

[85] The Conference Board of Canada: "Demographic Troubles and Opportunities in Energy, Newfoundland and Labrador's Outlook to 2045," February 22, 2023, at 3.
[86] Ibid, at 4.

c) Another key factor affecting Newfoundland and Labrador's long-term demographic outlook is the aging of its population, with many retirements expected over the coming decade. By 2045, we forecast the share of seniors in the province will reach 29.4 per cent – much higher than the 21.6 per cent anticipated for the country as a whole.[87]

d) The aging and declining population will weigh heavily on government finances, and government spendings are expected to decrease over the medium term.[88]

e) Consumer spending will decrease by an annual compound rate of 0.1 per cent throughout the forecast period. Spending will remain constrained due to the province's declining employment through the forecast period. It will also boast one of the highest unemployment rates. The unemployment rate will improve over the forecast period, falling from 11.3 per cent in 2023 to 9.1 per cent by 2045. However, the rate is declining for the wrong reason. The sharp drop in the provincial labour force will lead to a lower unemployment rate even though the employment picture will continue to be grim.[89]

f) The aging population will shift spending patterns, with spending on services faring relatively better than spending on goods, as the rise in the size of the elderly population will increase the demand for healthcare. We project that spending on services will rise by an average annual compound rate of 0.3 per cent. On the other hand, we forecast spending on goods to contract by 0.6 per cent annually until 2045.[90]

g) The oil and gas sector will see decent growth until the mid-2030s thanks to new offshore projects. After that, economic growth in the sector will start to decline as global oil demand peaks and Canada moves toward net zero by 2050.[91] However, spending in the sector is expected to be slow in the near-term as several projects are delayed or placed on hold.

h) The province's grim population outlook will also reverberate in the housing market. Housing starts have already started declining since 2011, and we project they will

[87] Ibid, at 6.
[88] Ibid, at 3.
[89] Ibid, at 11.
[90] Ibid, at 11
[91] Ibid, at 3.

continue to do so as the population decreases. We expect total housing starts to average less than 200 units annually through the forecast period.[92]

i) We project government spending will decrease over the medium term as the provincial government grapples with high debt levels. Newfoundland and Labrador's elevated debt will also come under pressure from the Bank of Canada's recent interest rate hikes.[93]

Figure 38 compares Newfoundland and Labrador to Canada on a number of key macroeconomic indicators over the period from 2022-2045.

Figure 38: Key Economic Indicators – 2022-2045[94]

Economic Indicator	NL	Canada
GDP Growth	1.0%	1.7%
Labor Force	(0.7%)	0.9%
Employment	(0.6%)	0.9%
Household Disposable Income	1.3%	3.2%
Retail Sales	2.4%	2.2%
Housing Starts	(11.7%)	(1.9%)

As shown in Figure 38, Newfoundland Power's business environment is characterized by weak long-term macroeconomic growth. Furthermore, Newfoundland and Labrador is projected to be weaker than Canada overall on each of these key economic indicators from 2022-2045 with the exception of retail sales, which is projected to be slightly stronger. In addition, as discussed in Newfoundland Power's evidence, the population demographics of Newfoundland and Labrador are weak in relation to the rest of Canada, and population is expected to decline over the long-term.

Economic and demographic trends in the province will weigh on Newfoundland Power's electric sales growth in coming years, offset over the medium to longer term by increasing electrification measures. Regardless of changes in demand for power, the Company needs to continue investing capital to maintain and modernize its aging infrastructure so that service quality and reliability

92 Ibid, at 10.
93 Ibid, at 14
94 The Conference Board of Canada, Provincial Outlook to 2045, Key Economic Indicators, March 20, 2023.

are not compromised. However, at the same time, as discussed in more detail later in this report, there is ongoing risk of higher electricity rates due to higher power supply costs, placing downward pressure on electricity usage. For all of these reasons, it is important that Newfoundland Power be allowed to maintain a capital structure that reflects the risk associated with long-term macroeconomic and demographic trends in the Province.

e. Operating Risks

Newfoundland Power is an integrated electric utility serving approximately 274,000 residential and commercial customers on the island portion of Newfoundland and Labrador. In 2022, the Company had an electric rate base of approximately $1.2 billion and delivered 5,785 GWh of power. Newfoundland Power purchases approximately 93 percent of its electricity supply from Newfoundland and Labrador Hydro ("NLH"), while generating the remaining 7 percent using company-owned hydro-electric plants. One of the most important operating risks for Newfoundland Power is weather-related service disruptions. As described in the Company's risk evidence, Newfoundland Power's service territory is characterized by the most severe ice and wind conditions in the populated regions of Canada. The need to address service disruptions caused by severe weather conditions involves unanticipated and potentially volatile capital and operating costs. Newfoundland Power's capital structure and allowed ROE should provide the Company with the financial flexibility necessary to respond to unforeseen capital and operating costs in order to restore electric service promptly to customers.

f. Power Supply Risk

Newfoundland Power is not allowed to develop new power supply for the Province with the exception of emergency supply; only NLH is authorized to build generation. The Muskrat Falls project including the Labrador-Island Link ("LIL") transmission project was officially commissioned into service on April 12, 2023.[95] The Muskrat Falls project, including the LIL, was originally intended to replace NLH's Holyrood Thermal Generating Station ("Holyrood TGS"), but to help ensure reliable service for customers, NLH has committed to maintaining the Holyrood TGS and the Hardwoods Gas Turbine as generating facilities until new generation can be integrated into the system, possibly through to 2030.[96] Questions remain about the reliability of NLH's current and future generation sources, as well as concerns regarding the impact of new

[95] Newfoundland and Labrador Hydro's Near-Term Reliability Report, June 2, 2023, at 4.
[96] Ibid, at 39.

power supply on electricity rates. There also is an ongoing review by the Board into the future reliability of NLH's power supply.

The cost of the Muskrat Falls generation and transmission facility increased from the original estimate of $7.4 billion when our evidence was filed in 2018 to approximately $13.1 billion in 2021, as compared to NLH's 2022 average rate base of about $2.3 billion. The final cost is reported as $13.5 billion.[97] In order to mitigate the rate impact on customers, the federal and provincial governments have agreed on a package of measures that include 1) a $1 billion federal loan guarantee, 2) capital restructuring of the Muskrat Falls project and Labrador transmission assets, and 3) a $1 billion investment by the federal government in the province's portion of the LIL.[98] Newfoundland Power's future supply costs are dependent on a number of factors including the finalization of government's rate mitigation plan, NLH's next general rate application, and the cost of additional supply that may be required to ensure reliable service to customers.

Both Moody's and DBRS have expressed concern over the risk for Newfoundland Power due to higher supply costs, and how those supply costs might impact customer demand for electricity and timely cost recovery for the Company. Moody's has commented on the power supply situation as follows:

> *The credit profile is negatively impacted by the risk of future cost recovery associated with the Province of Newfoundland and Labrador's sizeable Muskrat Falls hydroelectric project. This politically sensitive project is large relative to the provincial economy and may place significant upward pressure on the future electricity rates of NPI, a credit negative.*[99]

Similarly, DBRS Morningstar has stated:

> *DBRS Morningstar continues to consider the greatest uncertainty for Newfoundland Power to be the potential rate shock from Newfoundland and Labrador Hydro's (Hydro; 100% owned by the Province of Newfoundland and Labrador; both rated "A" with a*

97 Moody's Investors Service, Credit Opinion: Newfoundland Power, Inc. Update to credit analysis, March 31, 2023, at 1.

98 CBC News, "Ottawa's $5.2 billion Muskrat bailout includes more borrowing, restructuring as project nears completion," February 14, 2022.

99 Moody's Investors Service, Credit Opinion: Newfoundland Power, Inc. Update to credit analysis, March 31, 2023, at 1.

> *Stable trend by DBRS Morningstar) Muskrat Falls Project (Muskrat Falls). While the generating units were completed in 2021 and the associated Labrador-Island Link (LIL) transmission line was officially commissioned in April 2023, the impact on customer rates remains subject to Hydro's future general rate applications (GRAs). Should the upward pressure on rates affect the Company's ability to pass on costs, this would negatively affect its credit profile. DBRS Morningstar will continue to monitor the situation and treat a potential rate shock as an event risk.*[100]

In its 2016 Order, the Board cited the risk associated with the Muskrat Falls project as one reason to maintain Newfoundland Power's common equity ratio at 45 percent. The Board stated:

> *In the circumstances the Board does not believe it is appropriate to deem a reduced common equity ratio for Newfoundland Power given the uncertainty associated with Muskrat Falls and the economic outlook for the province and also in light of the concerns set out by Newfoundland Power in relation to the issuance or deeming of preferred shares. The Board is concerned about the impact of such a change on Newfoundland Power's credit metrics and how this would be viewed by the markets. The Board believes that the circumstances require a conservative and stable regulatory approach and therefore Newfoundland Power's deemed common equity ratio will not be lowered at this time.*[101]

Given the increased cost of the Muskrat Falls hydroelectric project and the need to provide backup for this LIL, the power supply risk for Newfoundland Power remains elevated, similar to the circumstances at the time of the 2016/2017, 2019/2020 and 2022/2023 GRA filings.

Furthermore, according to Newfoundland Power's evidence, power supply costs accounted for approximately 65 percent of the Company's 2022 revenue. To assess how Newfoundland Power's power supply risk compares to that of the proxy group, we studied the relative power supply costs of the proxy group companies. Specifically, we compared bundled revenue (*i.e.*, including both power and delivery revenue) as reported in EIA Form 861 to power production operating expenses (which includes purchased power expenses) as reported in FERC Form 1 for the operating subsidiaries of our proxy group companies, to the extent available. This analysis indicates that power supply costs account for approximately 51 percent of the proxy group's revenues on average, or approximately 14 percent less than Newfoundland Power. This suggests

[100] DBRS Morningstar Rating Report, Newfoundland Power Inc., October 13, 2023, at 1.
[101] Order No. P.U. (18)2016, at 25.

that Newfoundland Power faces relatively more power supply risk than the proxy group on average.

Newfoundland Power recovers changes in power supply costs through the Rate Stabilization Account ("RSA"), which allows for recovery of variations in NLH's production costs. The RSA also recovers or credits, as appropriate, variations in Newfoundland Power's supply costs due to changes from test year energy and demand costs. In its Application, Newfoundland Power is proposing changes to its Demand Management Incentive ("DMI") threshold to +/-$500,000, which represents approximately 15 percent of the range of return on rate base typically approved by the Board. By contrast, the vast majority of distribution utilities in Canada and the U.S. are allowed to pass through all fuel and purchased power costs.

g. Alternative Fuel Risk

Currently, Newfoundland Power does not face significant competition from alternative fuel sources. Approximately 74 percent of Newfoundland Power's residential customers use electricity for space heating.[102] Most recently, increases in the price of fuel oil combined with government incentives to convert from oil to electric heating have increased the number of Newfoundland Power customers using electric heat. To reduce electricity consumption related to space heating, Newfoundland Power customers have increased their purchases of heat pumps to offset electric baseboard heating. Penetration of heat pumps has increased from 4 percent in 2014 to 28 percent in 2022. This heat pump penetration has a tendency to reduce the average electricity use per customer for Newfoundland Power and contributes to the decrease in electricity sales that was experienced by Newfoundland Power from 2016 to 2021.

As discussed previously, the completion of the Muskrat Falls development and additional costs associated with constructing new sources of supply has the potential to result in higher electricity prices for Newfoundland Power customers. Increases in the price of electricity will signal customers to find more ways to either conserve electricity or use alternate sources of energy.

h. Conclusions on Business Risk

Historical risks have continued to persist, and the business risk for Newfoundland Power is comparable to that in 2021 for the Company's previous GRA filing. In particular, from an

[102] Newfoundland Power Inc. 2022 Annual Information Form, at 3.

investors' perspective the risk associated with higher electricity prices remains elevated, and the electricity supply from NLH continues to pose risks to both reliability and costs. Credit rating agencies are monitoring this situation very closely and have expressed serious concerns with how higher electricity prices might affect demand for electricity in the Province as well as the cash flows and earnings for Newfoundland Power. The risk related to macroeconomic and demographic trends has not changed, as the Provincial economy is projected to continue experiencing weaker economic growth and demographics over the next 20 years. The Company's business risk profile magnifies Newfoundland Power's risk associated with its small size. Further, there are limited opportunities for customer growth in the Company's service territory, although electrification is expected to contribute to higher use per customer.

3. Comparison to other Canadian Investor-Owned Electric Utilities

Concentric also compared the business risk of Newfoundland Power to five other Canadian investor-owned electric utilities to assess whether the Company continues to be an average risk Canadian utility, as the Board has found in previous decisions.[103] Those five investor-owned electric utilities are: ATCO Electric; FortisAlberta; FortisBC Electric; Maritime Electric; and Nova Scotia Power.[104]

In assessing the business risk of Newfoundland Power relative to other Canadian investor-owned electric utilities, Concentric considered the following factors:

a) Power supply risk and electricity prices;

b) Macro-economic and demographic conditions in the various service territories;

c) Volume/demand risk;

d) Competition from alternative fuels;

e) Regulatory environment; and

f) Capital and operating cost recovery.

[103] Order No. P.U. 13(2013), at 17.

[104] Concentric did not include crown corporations in the risk comparison because crown corporations cannot be used for purposes of estimating the cost of equity since they are not publicly traded and no market data are available.

a. Power Supply Risk

As discussed in the previous section, Newfoundland Power purchases approximately 93 percent of its power supply from NLH. The price of Newfoundland Power's electricity supply is expected to increase due to costs associated with the Muskrat Falls development and future supply costs that were previously unanticipated such as the continued operation of the Holyrood TGS and Hardwoods Gas Turbine. This could potentially place pressure on Newfoundland Power's demand over the medium to longer term. Newfoundland Power's RSA permits recovery of the difference between the marginal energy supply cost and the average energy supply cost. Newfoundland Power is also proposing changes to its DMI account to limit its risk of recovery of supply costs to +/- $500,000, or approximately 15 percent of the range of return on rate base typically approved by the Board. The primary purpose of the RSA is to ensure that variations in NLH's production costs approved by the PUB are recovered in or credited to Newfoundland Power's customer rates in a timely fashion. Newfoundland Power also has an Energy Supply Cost Variance Clause which captures changes in the Company's marginal purchased power costs related to variances in customers' load requirements. To ensure reasonable recovery of this supply cost between GRAs, the Board has approved the annual recovery of energy cost variances for Newfoundland Power through the RSA.

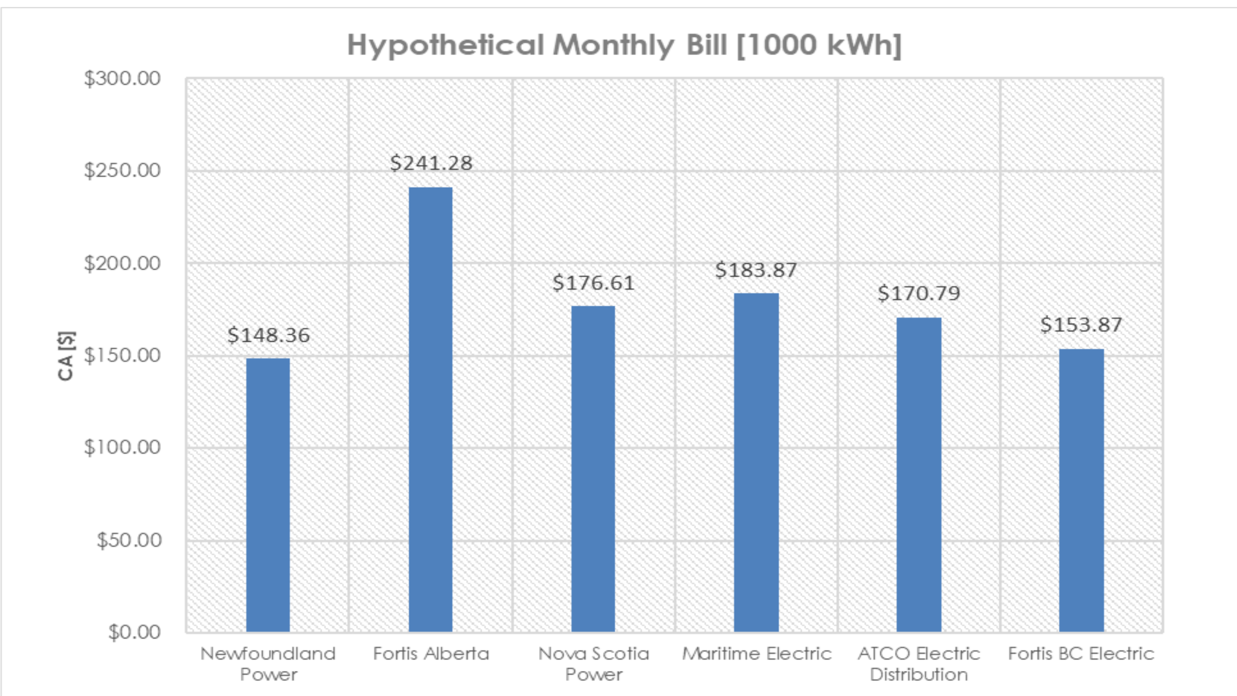
Nova Scotia Power is the only Canadian investor-owned electric utility that owns significant regulated generation; it recovers prudently incurred increases and/or decreases in its cost of fuel outside of general rate proceedings through periodic adjustments to customer rates via an annual fuel adjustment mechanism. FortisBC Electric generates approximately 45 percent of its power supply from company-owned hydro plants and has an annual fuel and purchased power cost recovery mechanism. Maritime Electric purchases almost all of its power supply but owns limited regulated generation for backup. FortisBC Electric has an annual fuel and purchased power cost recovery mechanism, and Maritime Electric has a monthly fuel and purchased power cost recovery mechanism. The Alberta electric utilities (i.e., ATCO Electric and FortisAlberta) are not responsible for the generation function.

In summary, Newfoundland Power has more risk associated with recovery of variations in fuel or purchased power costs than other Canadian investor-owned electric utilities except for Nova Scotia Power. Moreover, Newfoundland Power is uniquely dependent on a single source of electric supply, creating greater supply risk than utilities such as FortisBC Electric, Nova Scotia Power, or the Alberta utilities that rely on a more diverse mix of generation and market sources.

b. Electricity Rate Comparison

As discussed above, Newfoundland Power's customer rates have the potential to increase once Muskrat Falls Project costs are included in customer rates and to address reliability concerns that may necessitate new sources of supply for customers on the island portion of Newfoundland and Labrador. Increasing customer electricity rates can place downward pressure on electricity sales growth over the medium to longer-term. Newfoundland Power's residential electricity rates are currently lower than the five other investor-owned electric utilities in Canada. Newfoundland Power also has the highest proportion of electric space heating compared to the other electric utilities shown in Figure 39, increasing the impacts of changes in rates.

Figure 39: Residential Electricity Rate Comparison



The magnitude of the forecasted increase for Newfoundland Power is expected to be driven by the $13.5 billion Muskrat Falls Project and the ability of the Newfoundland and Labrador Government to mitigate those costs for customers. Further cost pressure is expected from continued operation of the Holyrood TGS and potential new supply additions required to reliably serve Newfoundland Power's customers in the future. Higher rates typically result in lower electricity demand from customers, as well as more customers considering alternative sources of energy. It is reasonable to expect that the potential increases in electricity rates due to future supply costs could place pressure on Newfoundland Power's demand (although this may be partially mitigated by electrification), which could impact the Company's credit metrics and inhibit the Company's ability to earn its authorized return on equity.

c. Macroeconomic and Demographic Conditions

Long-term macroeconomic conditions in Newfoundland and Labrador are generally projected by the Conference Board to be weaker than other Canadian provinces for the period from 2022-2045. Figure 40 compares the projected macroeconomic conditions in Newfoundland and Labrador to those in the provinces where the other five investor-owned electric utilities are located, as well as Quebec.

Figure 40: Key Economic Indicators – NL and Other Provinces[105]

	NL	ALB	BC	NS	ONT	PEI	QC
GDP Growth	1.0%	2.0%	2.0%	1.5%	1.9%	1.7%	1.5%
Labour Force	(0.7%)	1.4%	1.1%	0.6%	1.0%	1.0%	0.3%
Employment	(0.6%)	1.4%	1.1%	0.6%	1.0%	1.0%	0.3%
Disposable Inc.	1.3%	3.7%	3.5%	2.9%	3.2%	3.6%	2.2%
Retail Sales	2.4%	2.7%	3.4%	2.3%	1.9%	2.1%	2.7%
Housing Starts	(11.7%)	(0.5%)	(1.8%)	(6.6%)	(0.9%)	(3.0%)	(9.6%)

As shown in Figure 40, Newfoundland and Labrador has the lowest projected growth rate for many key economic indicators over the period from 2022-2045 (i.e., real GDP growth, labour force, employment, disposable income, and housing starts), and the differences are significant in many cases. Retail sales growth is the only key economic indicator in Figure 40 in which Newfoundland and Labrador ranks higher than other Canadian provinces (i.e., fourth out of seven provinces).

d. Volume/Demand Risk

In order to mitigate volume/demand risk, Newfoundland Power has a weather-related variance account that allows the Company to recover in a future period the difference between projected and actual revenues due to abnormal weather conditions in the test year. This variance account, however, does not take into consideration changes in demand caused by economic conditions, electricity prices, or energy efficiency and conservation programs.

By comparison, among Canadian investor-owned electric utilities, FortisBC Electric operates under a revenue stabilization plan that includes full protection against volumetric risk. Nova Scotia Power does not have any mechanisms that protect revenue against fluctuations in demand.

[105] The Conference Board of Canada, Provincial Outlook to 2045, Key Economic Indicators, March 20, 2023.

ATCO Electric Distribution and FortisAlberta both are subject to a performance-based regulation ("PBR") plan that adjusts revenues annually based on inflation less a productivity factor; however, the PBR plan does not include protection against fluctuations in volume/demand. Maritime Electric has a weather normalization clause that protects against changes in volume/demand due to abnormal weather. In summary, Newfoundland Power's weather-related variance account provides less regulatory protection against changes in volume/demand than FortisBC Electric, but more protection than Nova Scotia Power or the Alberta electric utilities. Newfoundland Power has the highest market share of electric heating customers among Canadian investor-owned electric utilities. The Company has implemented a weather-related variance account to mitigate this risk. The Company's volumetric/demand risk is more analogous to a gas distribution company than to the typical electric utility. Gas distribution companies typically have weather normalization accounts.

e. Regulatory Environment

UBS, a prominent investment bank, ranks regulatory jurisdictions in the U.S. and Canada for purposes of determining whether to apply valuation discounts or premiums to the utility stocks it covers. Specifically, UBS places regulatory jurisdictions into five tiers based on the following equally weighted criteria: (1) whether commissioners are elected or appointed, (2) allowed returns relative to 10-year Treasury notes, (3) mechanisms that reduce regulatory lag, (4) rate and customer bill levels, (5) the tendency to settle or litigate rate cases, and (6) a subjective "investor friendliness" factor.[106] UBS ranked Newfoundland and Labrador's regulatory environment in tier three out of five in a December 2020 report.[107] UBS also placed Ontario and Prince Edward Island in tier three. British Columbia and Nova Scotia were rated more highly by UBS, falling in tiers one and two, respectively, while Alberta was rated in tier four.

S&P also assesses the credit supportiveness of regulatory jurisdictions in U.S. states and Canadian provinces. Specifically, S&P groups jurisdictions into five tiers ranging from "credit supportive" to "most credit supportive." S&P ranks Newfoundland and Labrador in its second most favorable category (i.e., "highly credit supportive") along with Alberta. British Columbia, Nova Scotia, Ontario, and Quebec are ranked in the most favorable category (i.e., "most credit supportive"),

[106] UBS Global Research, "North America Power & Utilities: Mind the Gap(s): 2021 Utility Outlook," December 14, 2020, at 5.
[107] Ibid., at 6.

and Prince Edward Island is ranked in S&P's least favorable category (i.e., "credit supportive"). However, S&P notes that all regulation is credit supportive, and that its rankings are only a matter of degree:

> *The categories are an important starting point for assessing utility regulation and its effect on ratings. They are all credit-supportive to one degree or another, as all utility regulation tends to sustain credit quality. The presence of regulators, no matter where on the spectrum of our assessments, reduces business risk and generally supports utility ratings. We therefore designate all these jurisdictions from credit supportive to most credit supportive, and these vary only in degree.*[108]

f. Capital Cost Recovery

Newfoundland Power files a capital budget with the Board annually, which includes the Company's capital budget for the upcoming year, as well as a five-year outlook. The Board approves capital expenditures for the coming year. Similarly, Nova Scotia Power, FortisBC Electric, and Maritime Electric also file for pre-approval of certain capital expenditures. In Alberta, the Alberta Utilities Commission ("AUC") approved a new third generation PBR plan for distribution utilities for the period 2024-2028.[109] The AUC has continued to distinguish between two types of capital costs. Costs associated with Type 1 capital are subject to a true up, but the Type 1 capital criteria are restrictive (*i.e.*, must be extraordinary, not previously in rate base, required by a third-party, *e.g.*, regulatory or legislative authority related to net-zero objectives, and project cost must have material effect on distribution utility).[110]

Electric utilities in Canada are not allowed to earn a cash return on Construction Work in Progress ("CWIP"), but all utilities are permitted an Allowance for Funds Used During Construction ("AFUDC"). In summary, Newfoundland Power has similar risk associated with capital cost recovery as other investor-owned electric utilities in Canada except for those in Alberta, which have higher risk on certain capital costs.

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108 S&P Global RatingsDirect, "Updated Views on North American Utility Regulatory Jurisdictions – June 2021," June 29, 2021, at 2.
109 AUC Decision 27388-D01-2023 (October 4, 2023).
110 AUC Decision 27388-D01-2023 (October 4, 2023), at para 250-268.

g. Operating Cost Recovery

Concentric has identified several categories of operating costs where cost recovery mechanisms tend to vary between jurisdictions. These are costs that (1) tend to fluctuate substantially from year to year, (2) are significant in magnitude, and (3) are generally beyond the control of utility management. Regulators in Canada have typically used variance and deferral accounts to mitigate the risks associated with these types of costs. As shown in Figure 41, Newfoundland Power has deferral/variance accounts for employee future benefits expenses and energy efficiency and conservation costs, while other Canadian investor-owned electric utilities have varying levels of protection against these risks, with the exception of FortisAlberta, which does not have any deferral/variance accounts related to these costs.

Figure 41: Operating Cost Recovery Mechanisms

Cost	Pension/OPEB Expense	Bad Debt Expense	Extraordinary Storm Costs	Change in Interest Rates	Energy Efficiency and DSM
Newfoundland Power	Yes	No	No	No	Yes
ATCO Electric	Yes	No	Yes	Yes	No
FortisBC Electric	Yes	No	Yes	Yes	Yes
FortisAlberta	No	No	Yes	No	No
Hydro One Networks	Yes	Yes	N/A	No	Yes
Maritime Electric	Yes	No	No	No	Yes
Nova Scotia Power	No	No	Yes	No	No

Importantly, Newfoundland Power does not have a mechanism to recover extraordinary storm-related costs despite operating in a service territory characterized by the most severe ice and wind conditions in Canada. Nova Scotia Power was recently allowed to implement a storm cost recovery rider for extraordinary storm costs beyond specified levels. ATCO Electric, FortisAlberta and FortisBC's electric utility are allowed to recover extraordinary storm-related costs under terms of their respective PBR plans on a case-by-case basis under the Z factor (i.e., an exogenous cost that is beyond management control and from an unforeseen event). This is an important factor that differentiates Newfoundland Power from several Canadian electric utilities and increases the Company's business risk.

h. Conclusions on Business Risk Compared to Other Canadian Electric Utilities

Concentric concludes that Newfoundland Power has above average business risk compared to other Canadian electric utilities. In particular, factors contributing to this higher risk profile include Newfoundland Power's small size, dependence on one supplier, weaker macroeconomic and demographic trends in the province as compared to the remainder of Canada, and weather and storm-related risk. While the regulatory framework in Newfoundland and Labrador is generally supportive of maintaining credit quality, there are certain aspects of the operating environment where Newfoundland Power has higher business risk than other Canadian investor-owned electric utilities. Further, Newfoundland Power has more power supply risk than other Canadian investor-owned electric utilities due to the cost of the Muskrat Falls project combined with additional costs associated with bulk electricity supply on the island portion of Newfoundland and Labrador that were previously not anticipated.

The small size of Newfoundland Power in terms of retail customers and revenues from electric utility service makes the Company more vulnerable to changes in customer demand due to economic and demographic conditions in the Province. Furthermore, the rising cost of the electricity supply for Newfoundland Power has the potential to contribute to an increase in electricity rates, which places pressure on customer demand and raises uncertainty regarding cost recovery. Compared to other electric utilities in Canada, Newfoundland Power has more risk associated with variations in purchased power costs due to the limitations associated with the RSA. As mentioned, Newfoundland Power is exposed to elevated storm-related risk in its service territory but does not have regulatory protection that ensures recovery of unanticipated storm-related costs through a deferral account, unlike several other investor-owned electric utilities in Canada.

4. <u>Comparison to U.S. Electric Utility Proxy Group</u>

a. Regulated Electric Utility Operations

Newfoundland Power derives 100 percent of its operating income and revenues from regulated electric utility service. As shown in Exhibit JMC-12, the U.S. Electric utility proxy group companies derive approximately 97 percent of income from regulated service, approximately 96 percent of regulated revenues and regulated income is from electric utility service, and approximately 96 percent of regulated assets are dedicated to electric utility operations. For this reason, we believe that the U.S. Electric utility proxy group is more representative of Newfoundland Power's electric utility operations than the Canadian proxy group companies, which generally derive substantially lower percentages of operating income and revenues from electric utility service, and have a lower percentage of assets dedicated to electric utility operations.

b. Credit Rating Agency View on U.S. Regulatory Framework

In September 2013, Moody's issued a report discussing its evolving view of U.S. utility regulation. In that report, Moody's stated:

> *Based on our observations of trends and events, we propose to adopt a generally more favorable view of the relative credit supportiveness of the U.S. utility regulatory environment. Our updated view considers improving regulatory trends that include the increased prevalence of automatic cost recovery provisions, reduced regulatory lag, and generally fair and open relationships between utilities and regulators.*
>
> ***
>
> *Our revised view that the regulatory environment and timely recovery of costs is in most cases more reliable than we previously believed is expected to lead to a one notch upgrade of most regulated utilities in the U.S., with some exceptions. This evolving view is independent of the proposed changes in the methodology that are highlighted in the Summary section that follows, and would have taken place even if the 2009 methodology were to remain in place without modification.*[111]

More recently, a March 2019 report by equity analysts at Scotiabank indicated that they view the regulatory environments in Canada and the U.S. as being similar for regulated utilities. In explaining why they expect the valuations of Canadian and U.S. utilities to converge, Scotiabank observed:

> Canadian and U.S. valuations should converge. Historically, the Canadian utilities have traded at a premium to their mid-cap U.S. peers. **We attribute this to the historical view that Canadian regulation was superior to U.S. regulation (we no longer have that view)** as well as to strong earnings growth in part due to M&A. As

[111] Moody's Investors Service, "Proposed Refinements to the Regulated Utilities Rating Methodology and our Evolving View of US Utility Regulation," September 23, 2013, at 1.

> shown in Exhibit 19, based on forward consensus estimates, the Canadian names now trade at a 3x discount.[112]

The Moody's and Scotiabank reports confirm our assessment of the comparability of the U.S. and Canadian regulatory environments.

c. Comparison to U.S. Electric Utility Proxy Group

As a preliminary matter, Concentric notes that from the investors' perspective, both short-term and long-term risk are important. Regulation generally is better at addressing short-term risk, whereas long-term risk cannot be mitigated as effectively by regulation. For example, changes in competitive positioning vs. alternative fuels, shifts in service area demographics, or policy mandates impacting long-term business prospects may not be fully protected. Exhibit JMC-13 compares the business risk for Newfoundland Power to the U.S. Electric utility proxy group. As shown in that Exhibit, and summarized below, Newfoundland Power generally has comparable business risk as the U.S. Electric Utility proxy group.

a) Regulated generation risk: Newfoundland Power owns limited regulated generation assets and therefore has lower generation risk than the U.S. Electric utility proxy group operating companies, the majority of which own some regulated generation assets.

b) Fuel and purchased power cost risk: Newfoundland Power purchases approximately 93 percent of its power supply from NLH and generates the remaining 7 percent of its energy supply from Company-owned hydro-electric plants. The Company is allowed to recover variations in NLH's production costs in a timely fashion through the RSA, subject to certain limitations described previously. All of the electric utility companies in the U.S. proxy group have fuel adjustment clauses that allow them to pass through prudently-incurred fuel and purchased power costs to customers. As such, the U.S. Electric utility companies are not at risk for differences between the projected and actual cost of fuel and purchased power. We note that Newfoundland Power's predominant reliance on a single source of power and the integration of the Muskrat Falls project places it at greater risk of supply disruptions than the average U.S. utilities, and the effective limitations on Newfoundland Power's RSA constrain the Company's ability to recover variations in purchased power costs.

[112] Scotiabank Equity Research Spotlight, Energy Infrastructure, March 18, 2019, at 9. [Emphasis added.]

c) Regulatory lag: Newfoundland Power files rate applications based on a forecasted test year, while 41 percent of operating companies in the U.S. Electric proxy group use fully or partially forecasted test years. Newfoundland Power's revenue requirement is determined based on average rate base, while 59 percent of operating companies in the U.S. proxy group use year-end rate base, which provides more timely recovery of capital investments than those with a historic test year.

d) Volume/demand risk: Newfoundland Power has a weather normalization adjustment clause that provides regulatory protection against changes in volume/demand caused by abnormal weather conditions. By comparison, approximately 54 percent of the operating companies in the U.S. Electric utility proxy group have full or partial revenue decoupling mechanisms that mitigate volume/demand risk.

e) Capital cost recovery risk: Newfoundland Power annually files a capital investment plan with the Board, and the Board approves a specified amount that will be recoverable in future rates. Approximately 74 percent of the operating companies in the U.S. Electric utility proxy group either receive pre-approval for capital expenditures and/or are allowed to earn a cash return on Construction Work in Progress. In addition, 85 percent have cost tracking mechanisms that allow them to recover capital costs between rate cases (for renewables expense, environmental compliance, generation capacity, generic infrastructure replacement, and transmission expense). Newfoundland Power does not have any capital tracking mechanisms and earns AFUDC on capital costs rather than a cash return on CWIP.

f) Operating cost recovery mechanisms: Newfoundland Power has been allowed to implement a number of deferral and variance accounts; likewise, the operating companies in the U.S. proxy group employ similar regulatory protection against specific categories of costs that tend to fluctuate significantly from year to year, are material in nature, and are beyond the control of utility management. For example, Newfoundland Power has an account for recovery of energy efficiency and conservation costs, and 80 percent of operating companies in the U.S. Electric utility proxy group also have an account for this purpose. A notable exception is that Newfoundland Power has limited protection against storm-related costs (both operating and capital costs), which tend to be a significant risk factor in any given year due to harsh climate conditions in the Province. Newfoundland Power is allowed to place storm-related capital investments in rate base, but cost recovery of that capital investment is delayed until the next rate case. Of the U.S. Electric utility proxy group companies, 37 percent of the operating companies have a storm-cost recovery account.

In addition to these short-term risks, as discussed previously, Newfoundland Power has higher long-term business risk than the U.S. proxy group companies due to (1) unfavorable demographic trends (e.g., Newfoundland Power serves an island where the population is aging and is expected to decline in absolute terms over the medium to long term), and (2) the fact that macroeconomic growth is projected to be weak in the Province over the medium to long term. In addition, Newfoundland Power's service territory is exposed to severe weather conditions, especially wind and ice storms that can lead to service disruptions during the winter months with a customer base that relies primarily on electric heating.

d. Conclusions on Business Risk of Newfoundland Power Compared to U.S. Electric Utility Proxy Group

Based on the business risk analysis, Concentric concludes Newfoundland Power has somewhat higher business risk than the proxy group of U.S. Electric utility companies. In particular, factors contributing to this higher risk profile include Newfoundland Power's small size, dependence on one supplier, and weather and storm related risk. Newfoundland Power has similar business risk to the U.S. Electric utility proxy group on most factors that affect the short and intermediate term variability of earnings and cash flows. Notable differences include: a) the approval of CWIP in rate base for companies in the U.S. proxy group; b) the use of forecasted test years for Newfoundland Power; and c) the prevalence of storm cost trackers for the U.S. proxy group. Further, Newfoundland Power faces a less favorable economic and demographic environment, as well as a more severe operating environment and smaller size.

One distinguishable difference in business risk between Newfoundland Power and the U.S. proxy group is the higher percentage of U.S. proxy group companies that own regulated generation assets. However, Newfoundland Power has an offsetting risk related to its reliance on a single source of electric supply and challenges associated with integration of the Muskrat Falls project. On balance, Newfoundland Power's business risk is somewhat higher than the operating companies in the U.S. Electric utility proxy group that would cause an investor to assign a higher risk profile to Newfoundland Power.

C. Risk Analysis Conclusions

Based on the results of the financial and business risk analyses discussed throughout this report, Concentric recommends that the Board find that:

- The small size of Newfoundland Power and the operating challenges of providing electricity in the Company's service territory continues to support a higher common equity ratio than other investor-owned electric utilities in Canada;
- Certain factors suggest that the business risk for Newfoundland Power remains elevated due to the Muskrat Falls project. While certain government rate mitigation plans have been introduced, new risks associated with the need to maintain backup for the LIL have been introduced. This includes the continued operation of Holyrood and the need for new supply once it is retired. This places upward pressure on the cost of the Company's power supply;
- Challenging demographic and macroeconomic trends in the Province place downward pressure on electricity demand over the medium to longer-term;
- Regulatory protections to mitigate business risk for Newfoundland Power generally are similar to those for the operating companies in the U.S. Electric utility proxy group;
- The business risk of Newfoundland Power is higher than that of other Canadian investor-owned electric utilities;
- The business risk of Newfoundland Power is comparable to the Company's business risk at the time of the last GRA in 2021; and
- The financial risk of Newfoundland Power with 45 percent common equity is comparable to that of the Canadian and U.S. electric utility proxy groups, based on an analysis of deemed equity ratios and key cash flow and interest coverage metrics.

Based on the foregoing, we conclude that the current deemed common equity ratio for Newfoundland Power of 45 percent remains the minimum appropriate level given these relative financial and business risks.

VII. AUTOMATIC ADJUSTMENT FORMULA

An automatic adjustment formula was originally established for Newfoundland Power in 1998. At that time, the Board stated that there may be circumstances which would render the use of a formula inappropriate for Newfoundland Power, including changes in financial market conditions which would suggest the formula is not accurately reflecting the appropriate return on equity.[113] In 2016, 2019 and 2022, the Board accepted the agreement between the parties that the continued suspension of the formula is appropriate.[114]

In the Company's evidence, Newfoundland Power requests continued suspension of the formula due to volatility in financial markets and ongoing economic uncertainty. We agree with Newfoundland Power's position that the Board should not re-instate an automatic adjustment formula for the Company at this time for the reasons discussed below.

Automatic Adjustment Mechanisms ("AAM") tied only to government bond yields were once prevalent across Canada. In the period following the global economic crisis in 2008-2009, when government bond yields were at their lowest levels and credit spreads near the highest levels, Canadian regulators began to recognize that ROE could not be reliably estimated through a simple relationship to government bond yields. In response, provincial regulators and the NEB either abandoned the formulaic approach to setting ROE, or adjusted the formula to incorporate a second factor, corporate credit spreads. The currently suspended BC formula, the revised Ontario formula, and the now suspended Quebec formula all adjusted their previous formulas to include a two-factor model that used forecast government bond yields while also incorporating utility credit spreads (over government bonds).[115] Incorporating a term for the credit spread between the utility bond and the long Canada bond yield helped to mitigate a fundamental weakness in the legacy formula: sole reliance on the Canadian long bond yield.

Today, only the OEB and the AUC use an ROE adjustment formula. The remainder of the provinces have either indefinitely suspended their use or have discontinued the formula altogether. Until recently, the two-factor formula had been working relatively well in Ontario, but in 2021 and 2022 it produced the lowest authorized ROEs for regulated utilities because bond yields (on which the formula is based) declined sharply even as risk for equity investors

113 Order No. P.U. 13(2013), at 36.
114 Order No. P.U. 18(2016), at 10, Order No. P.U. 2(2019), at 15, and Order No. P.U. 3(2022), at 17.
115 The BCUC recently declined to reinstate a formula, citing concerns with "uncertain economic conditions" and the "current high inflationary environment."

increased.[116] Alberta recently returned to the use of an adjustment formula similar to the one used in Ontario for 2024 and subsequent years.

Concentric has previously examined alternative inputs and parameters used to construct formulas and compared how formulas perform over time against non-formulaic results and under varying market conditions. Based on our analysis and assessment of alternatives, we concluded that all formulaic approaches run the risk of deviation from a fair return. We further concluded that fluctuations in financial markets are inevitable, and relationships between bond and utility equity securities cannot be fully anticipated by historical relationships, causing the results of ROE formulas to deviate from required equity returns. Consequently, periodic rate hearings remain the only reliable method for determination of utility ROEs, particularly during uncertain economic conditions.

VIII. OVERALL CONCLUSIONS AND RECOMMENDATIONS

For the reasons discussed throughout this report, it is appropriate to consider multiple methodologies including the DCF, CAPM and Risk Premium results when establishing the authorized ROE for Newfoundland Power. The results of our analyses are summarized in Figure 42.

Figure 42: Summary of Results[117]

	CANADIAN UTILITY PROXY GROUP	U.S. ELECTRIC PROXY GROUP	NORTH AMERICAN ELECTRIC PROXY GROUP
CONSTANT GROWTH DCF	10.03%	10.44%	10.07%
MULTI-STAGE DCF	10.17%	9.38%	9.42%
AVERAGE CAPM	10.09%	10.68%	10.37%
RISK PREMIUM		10.26%	10.26%
AVERAGE	**10.10%**	**10.19%**	**10.03%**

[116] The OEB ROE adjustment formula was producing results higher than the average of other investor-owned electric and gas utilities until more recent years.

[117] DCF results are based on 90-day average stock prices for proxy group companies. Results include 50 basis points for flotation costs and financial flexibility except for risk premium results.

We also present our results using only the Multi-Stage DCF model, the CAPM with a historical market risk premium, and the Risk Premium model. This provides a more conservative estimate of the cost of equity for Newfoundland Power. Those results are summarized in Figure 43.

Figure 43: Summary of Alternative Results

	CANADIAN UTILITY PROXY GROUP	U.S. ELECTRIC PROXY GROUP	NORTH AMERICAN ELECTRIC PROXY GROUP
MULTI-STAGE DCF	10.17%	9.38%	9.42%
HISTORICAL CAPM	9.57%	10.15%	9.86%
RISK PREMIUM		10.26%	10.26%
AVERAGE	**9.87%**	**9.93%**	**9.85%**

The average results of the Multi-Stage DCF, historical CAPM and Risk Premium methods for the North American Electric proxy group is 9.85 percent, within the range from 9.42 percent to 10.26 percent. The average for the Canadian proxy group is 9.87 percent and for the U.S. Electric proxy group is 9.93 percent. Based on this analysis, we believe a reasonable estimate of Newfoundland Power's cost of equity is 9.85 percent. In addition, a common equity ratio of 45.0 percent remains reasonable, if not conservative, given the business and financial risks of Newfoundland Power.

JAMES M. COYNE

SENIOR VICE PRESIDENT

Mr. Coyne provides financial, regulatory, strategic, and litigation support services to clients in the natural gas, power, and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry and provided testimony and expert reports before federal, state and provincial jurisdictions in the U.S. and Canada. Mr. Coyne holds a B.S. in Business from Georgetown University and an M.S. in Resource Economics from the University of New Hampshire.

AREAS OF EXPERTISE

Energy Regulation

- Rate policy
- Cost of capital
- Incentive regulation
- Fuels and power markets

Management and Business Strategy

- Fuels and power market assessments
- Investment feasibility
- Corporate and business unit planning
- Benchmarking and productivity analysis

Financial and Economic Advisory

- Valuation analysis
- Due diligence
- Buy and sell-side advisory

Litigation Support and Expert Testimony

- Rate and regulatory policy
- Fuels and power markets
- Contract litigation
- Valuation and damages

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2006 – Present)
Senior Vice President
Vice President

FTI Consulting (Lexecon) (2002 – 2006)
Senior Managing Director – Energy Practice

Arthur Andersen LLP (2000 – 2002)
Managing Director, Andersen Corporate Finance – Energy and Utilities

Navigant Consulting, Inc. (1996 – 2000)
Managing Director, Financial Services Practice
Senior Vice President, Strategy Practice

TotalFinaElf (1990 – 1996)
Manager, Corporate Planning and Development
Manager, Investor Relations
Manager of Strategic Planning and Vice President, Natural Gas Division

Arthur D. Little, Inc. (1989 – 1990)
Senior Consultant – International Energy Practice

DRI/McGraw-Hill (1984 – 1989)
Director, North American Natural Gas Consulting
Senior Economist, U.S. Electricity Service

Massachusetts Energy Facilities Siting Council (1982 – 1984)
Senior Economist – Gas and Electric Utilities

Maine Office of Energy Resources (1981 – 1982)
State Energy Economist

EDUCATION

University of New Hampshire
M.S., Resource Economics, *with honors*, 1981

Georgetown University
B.S., Business Administration and Economics, *cum laude*, 1975

DESIGNATIONS AND AFFILIATIONS

Community Rowing Inc., Board of Directors, 2015 - 2019

Georgetown University, Alumni Admissions Interviewer, 1988 – current

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001

American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996

National Petroleum Council, Regulatory and Policy Task Forces, 1992

President, International Association for Energy Economics, Dallas Chapter, 1995

Gas Research Institute, Economics Advisory Committee, 1990-1993

NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984

PUBLICATIONS AND RESEARCH

"Advancing FERC's Methodology for Determining Allowed ROEs for Electric Transmission Companies," submitted to FERC on behalf of EEI, James Coyne, Joshua Nowak and Julie Lieberman, May, 2020.

"Regulator Rationale for Ratepayer-Funded Electricity and Natural Gas Innovation", James M. Coyne, Robert C. Yardley, Jr. and Jessalyn G. Pryciak, Energy Regulation Quarterly, Volume 6, Issue 3, 2018.

"Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" (with Robert Yardley), prepared for the Canadian Gas Association and Canadian Electricity Association, May 2015.

"Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010

"A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June 2007

"Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006

"Winners and Losers: Utility Strategy and Shareholder Return" (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004

"Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003

"The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001

Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992

"Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

SELECTED SPEAKING ENGAGEMENTS

"The Market Risk Premium: An In-Depth Review", Society of Utility and Regulatory Financial Analysts 53rd Financial Forum, Richmond, VA, April 28,2022

"Energy Sector in Transition", Ontario Energy Association, Toronto, ON, September 24, 2018.

"Understanding Regulated Utilities in Today's Capital Markets", NARUC Annual Meeting, La Quinta, CA, November 14, 2016.

"Rate of Return: Where the Regulatory Rubber Meets the Road," CAMPUT Annual Conference, Montreal, Quebec, May 17, 2016.

"Innovations in Utility Business Models and Regulation", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2015 Energy Regulation Course, Queens University, Kingston, Ontario, June 2015

"M&A and Valuations," Panelist at Infocast Utility Scale Solar Summit, September 2010

"The Use of Expert Evidence," The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010

"A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008

"Nuclear Power on the Verge of a New Era," moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005

"The Investment Implications of the Repeal of PUCHA," Skadden Arps Client Conference, New York, NY, October 2005

"Anatomy of the Deal," First Annual Energy Transactions Conference, Newport, RI, May 2005

"The Outlook for Wind Power," Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005

"Direction of U.S. M&A Activity for Utilities," Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002

"Outlook for U.S. Merger & Acquisition Activity," Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001

"Investor Perspectives on Emerging Energy Companies," Panel Moderator at Energy Venture Conference, Boston, MA, June 2001

"Electric Generation Asset Transactions: A Practical Guide," workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999

"New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999

"Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998

"Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Alberta Beverage Container Management Board				
Alberta Beverage Container Management Board	2016 2019	Expert for the Board	N/A	Return Margin on Bottle Depots
Alberta Utilities Commission				
ATCO Utilities Group	2008 2009	ATCO Gas; ATCO Pipelines Ltd.; ATCO Electric Ltd.	Application No. 1578571 / Proceeding ID. 85	2009 Generic Cost of Capital Proceeding (Gas & Electric)
Enmax Power Corporation	2017	Enmax	22570	Cost of Common Equity
Enmax Power Corporation	2020	Enmax	24110	2021 Generic Cost of Capital
Enmax Power Corporation	2023	Enmax	27084	2024 and Beyond Cost of Capital Parameters
American Arbitration Association				
TransCanada Corporation	2004	TransCanada Corporation	AAA Case No. 50T 1810018804	Valuation of Natural Gas Pipeline
British Columbia Utilities Commission				
FortisBC	2012	FortisBC Utilities	G-20-12	Cost of Capital Adjustment Mechanisms
FortisBC	2015 2016	FortisBC Utilities	G-129-16	Cost of Capital (Gas and Electric Distribution)
FortisBC	2022	FortisBC Utilities	G-217-22	Cost of Capital (Gas and Electric Distribution)
California Public Utilities Commission				
San Diego Gas & Electric Company	2019	San Diego Gas & Electric Company	A-19-04-014	Cost of Capital (Electric & Gas Distribution)
San Diego Gas & Electric Company	2021	San Diego Gas & Electric Company	A-21-08-014	Cost of Capital (Electric & Gas Distribution)
Southern California Gas Company	2022	Southern California Gas Company	A-22-04-011	Cost of Capital (Gas Distribution)
San Diego Gas & Electric Company	2022	San Diego Gas & Electric Company	A-22-04-012	Cost of Capital (Electric & Gas Distribution)
Canada Energy Regulator				
Enbridge Pipelines Inc.	2021	Enbridge Pipelines Inc.	RH-001-2020	Cost of Capital (Oil Pipeline)
Connecticut Department of Public Utility Control				
Aquarion Water Company of CT/ Macquarie Securities	2007	Aquarion Water Company of CT	DPUC Docket No. 07-05-19	Return on Equity (Water)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Federal Energy Regulatory Commission				
Atlantic Power Corporation	2007	Atlantic Path 15, LLC	ER08-374-000	Return on Equity (Electric)
Atlantic Power Corporation	2010	Atlantic Path 15, LLC	ER11-2909-000	Return on Equity (Electric)
Atlantic Power Corporation	2011	Atlantic Path 15, LLC	ER11-2909 and EL11-29	Rate of Return (Electric Transmission)
Startrans IO, LLC	2012	Startrans IO, LLC	ER-13-272-000	Cost of Capital (Electric Transmission)
Startrans IO, LLC	2015	Startrans IO, LLC	ER-16-194-000 and EL16-25-000	Cost of Capital (Electric Transmission)
Northern States Power Company	2019	Northern States Power Company	ER20-26-000	Cost of Capital (Electric Transmission)
PPL Electric Utilities Corp.	2020	PP&l Industrial Customer Alliance v. PPL Electric	EL20-48-000	Answering Testimony in Response to a Section 206 ROE Complaint
South First Energy Operating Companies	2020	South First Energy Operating Companies	ER21-253-000	Cost of Capital (Electric Transmission)
DCR Transmission, L.L.C.	2023	DCR Transmission, L.L.C.	ER23-___-000	Cost of Capital (Electric Transmission)
Florida Public Service Commission				
Florida Power & Light Company	2021	Florida Power & Light Company	Docket No. 20210015-EI	Cost of Capital (Electric)
Georgia Public Service Commission				
Georgia Power Company	2022	Georgia Power Company	44280	Cost of Capital (Electric)
Hawaii Public Utility Commission				
The Gas Company	2017	The Gas Company	Docket No. 2017-0105	Cost of Capital (Gas Distribution)
Maine Public Utilities Commission				
Bangor Hydro Electric Company	1998	Bangor Hydro Electric Company	MPUC Docket No. 98-820	Transaction-Related Financial Advisory Services, Valuation
Central Maine Power Company	2007	Central Maine Power Company	MPUC Docket No. 2007-215	Sales Forecast
Enmax Corporation	2019	Enmax Corporation	2019-00097	Regulatory Approval of Emera Maine Acquisition

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Versant Power	2021	Versant Power	MPUC Docket No. 2020-00316	Cost of Capital (Electric)
Versant Power	2022	Versant Power	2022-00XXX	Cost of Capital (Electric)
Maryland State Board of Contract Appeals				
Green Planet Power Solutions	2018	Green Planet Power Solutions and Maryland Bio Energy LLC v. Maryland Department of General Services	MSBCA 3061	Contract Litigation, Power Purchase Agreement, Damages Analysis
Massachusetts Superior Court				
Burncoat Pond Watershed District	2010	Central Water District v. Burncoat Pond Watershed District	WDCV 2001-0105	Valuation/Eminent Domain
Minnesota Public Utilities Commission				
Northern States Power Company	2015 2016	Northern States Power Company	E-002-GR-15-826	Cost of Capital (Electric)
Northern States Power Company	2017	Northern States Power Company	E002/M-17-797 G002/M-17-787 E002/M-17-818	Cost of Capital (Electric and Gas Rate Riders for Transmission, Renewable Generation and Gas Distribution)
New Brunswick Energy and Utilities Board				
Liberty Utilities (Gas New Brunswick) LP	2021	Liberty Utilities (Gas New Brunswick) LP	491	Cost of Capital (Gas)
Newfoundland and Labrador Board of Commissioners of Public Utilities				
Newfoundland Power	2016	Newfoundland Power	2016 GRA	Cost of Capital (Electric)
Newfoundland Power	2018	Newfoundland Power	2018 GRA	Cost of Capital (Electric)
Newfoundland Power	2021	Newfoundland Power	2021 GRA	Cost of Capital (Electric)
New Jersey Board of Public Utilities				
Conectiv	2000-2001	Atlantic City Electric Company	NJBPU Docket No. EM00020106	Transaction-Related Financial Advisory Services
North Carolina Utilities Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Duke Energy Carolinas, LLC	2023	Duke Energy Carolinas, LLC	E-7, Sub 1276	Return on Equity (Electric)
Nova Scotia Utility and Review Board				
Nova Scotia Power Inc.	2012	Nova Scotia Power Inc.	2013 GRA	Return on Equity/Business Risk (Electric)
Nova Scotia Power Inc.	2022	Nova Scotia Power Inc.	2022 GRA	Return on Equity/Business Risk (Electric)
Eastward Energy Inc.	2023	Eastward Energy Inc.	M10960	Return on Equity/Business Risk (Gas)
Ontario Energy Board				
Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	2009	Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	EB-2009-0084	Ontario Energy Board's 2009 Consultative Process on Cost of Capital Review (Gas & Electric)
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study and Cost of Capital (Gas Distribution)
Enbridge Gas Distribution	2014	Enbridge Gas Distribution	EB-2012-0459	Incentive Regulation Plan and Industry Productivity Study
Ontario Power Generation	2016	Ontario Power Generation	EB-2016-0152	Cost of Capital (Electric Generation)
Ontario Power Generation	2020	Ontario Power Generation	EB-2020-0290	Capital Structure (Electric Generation)
Enbridge Gas Distribution	2022	Enbridge Gas Distribution	EB-2022-0200	Capital Structure and Business Risk
Prince Edward Island Regulatory and Appeals Commission				
Maritime Electric Company	2015	Maritime Electric Company	UE20942	Return on Capital (Electric)
Maritime Electric Company	2022	Maritime Electric Company	UE20946	Return on Capital (Electric)
Public Utilities Commission of Ohio				
Duke Energy Ohio, Inc.	2022	Duke Energy Ohio, Inc.	2022-00372	Cost of Capital (Gas Distribution)
Duke Energy Ohio, Inc.	2023	Duke Energy Ohio, Inc.	22-507-GA-AIR	Cost of Capital (Gas)
Régie de l'énergie du Québec				

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Gaz Métro	2012	Gaz Métro	R-3809-2012	Return on Equity/Business Risk/ Capital Structure (Gas Distribution)
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2013	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3842-2013	Return on Equity/Business Risk (Electric)
Hydro-Québec Distribution	2014	Hydro-Québec Distribution	R-3905-2014	Remuneration of Deferral Accounts
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2015-2017	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3897-2014	Performance-Based Ratemaking
South Carolina Public Service Commission				
Piedmont Natural Gas Company	2022	Piedmont Natural Gas Company	2022-89-G	Return on Equity (Gas Distribution)
Duke Energy Progress	2022	Duke Energy Progress	Docket No. 2022-254-E	Return on Equity (Electric)
South Dakota Public Service Commission				
Northern States Power Company-MN	2012	Northern States Power Company-MN	EL 11-019	Return on Equity
Texas Public Utility Commission				
Texas New Mexico Power Company	2004	Texas New Mexico Power Company	PUC Docket No. 29206	Auction Process and Stranded Cost Recovery
U.S. Department of Commerce				
Government of Québec	2017	Duty Investigation of Uncoated Groundwood Paper from Canada	PUC Docket No. 29206	Contracting for Renewable Resources, Market Analysis, Damages Analysis
Vermont Public Service Board				
Vermont Gas Systems, Inc.	2006	Vermont Gas Systems, Inc.	VPSB Docket No. 7109	Models of Incentive Regulation
Vermont Gas Systems, Inc.	2012	Vermont Gas Systems, Inc.	Docket No. 7803A	Cost of Capital (Gas Distribution)
Green Mountain Power Corporation	2013	Green Mountain Power Corporation	Docket No. 8191	Return on Equity (Electric)
Vermont Gas Systems, Inc.	2016	Vermont Gas Systems, Inc.	Docket No. 8698/8710	Return on Equity (Gas Distribution)
Green Mountain Power Corporation	2017	Green Mountain Power Corporation	Docket No. Tariff-8677	Return on Equity (Electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Green Mountain Power Corporation	2018	Green Mountain Power Corporation	18-0974	Return on Equity (Electric)
State Corporation of Virginia				
Dominion Energy Virginia	2021	Virginia Electric and Power Company	PUR-2021-00058	Cost of Capital (Electric)
Wisconsin Public Service Commission				
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-170	Return on Equity (Electric)
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-171	Return on Equity (Electric)
Northern States Power Company	2011	Northern States Power Company	PSCW Docket No. 4220-UR-117	Return on Equity (Electric)
Northern States Power Company	2013	Northern States Power Company	PSCW Docket No. 4220-UR-119	Return on Equity (Gas & Electric)
Northern States Power Company	2015	Northern States Power Company	PSCW Docket No. 4220-UR-121	Return on Equity (Gas & Electric)
Northern States Power Company	2017 2019	Northern States Power Company	PSCW Docket No. 4220-UR-123, 4220-UR-124	Return on Equity (Gas & Electric)
Northern States Power Company	2021	Northern States Power Company	4220-UR-125	Cost of Capital (Electric, Affidavit)
Northern States Power Company	2023	Northern States Power Company	4220-UR-126	Cost of Capital (Electric & Gas)
Yukon Utilities Board				
ATCO Electric Yukon	2016	ATCO Electric Yukon	2016-2017 GRA	Return on Equity (Electric)

JOHN P. TROGONOSKI

Assistant Vice President

Mr. Trogonoski has over 30 years of experience in financial and economic analysis, utility regulation, due diligence, business valuation, property taxation, and program administration. Mr. Trogonoski has assisted clients with a variety of regulatory matters, including providing expert testimony and reports on cost of capital, merger approval, and business and financial risk analysis in both the U.S. and Canada. Prior to joining Concentric, Mr. Trogonoski was a member of the Staff of the Colorado Public Utilities Commission where he supervised the financial analysts in the energy and telecommunications sections and filed expert testimony on matters such as rate of return, cost allocation, rate design, incentive regulation, and public policy. He has an M.S. in Business Administration and a B.S. in Marketing from the University of Colorado at Denver.

REPRESENTATIVE PROJECT EXPERIENCE

Utility Consulting

- Testified on behalf of ENMAX Power Corporation in the Generic Cost of Capital proceeding before the Alberta Utilities Commission in June 2023.
- Filed expert testimony on behalf of Maritime Electric Company Ltd. on cost of capital before the Island Regulatory and Appeals Commission in Prince Edward Island in June 2022.
- Testified on behalf of Liberty Utilities Gas New Brunswick on cost of capital before the New Brunswick Energy and Utilities Board in July 2021.
- Testified on behalf of Maritime Electric Company Ltd. on cost of capital and a proposed earnings sharing mechanism before the Island Regulatory and Appeals Commission in Prince Edward Island in August 2019.
- Testified on behalf of Vermont Gas Systems, Inc. on cost of capital before the Vermont Public Utility Commission in September 2019.
- Filed expert testimony on behalf of Community Utilities of Pennsylvania Inc. on cost of capital before the Pennsylvania Public Utility Commission in March 2019.
- Filed expert testimony on behalf of Hydro-Quebec Distribution and Transmission in support of the Company's request to the Régie de l'energie to modify its allowed return on equity. Performed risk analysis to determine whether it was appropriate to consider a U.S. peer group of regulated electric utilities as an appropriate proxy group for purposes of establishing the allowed ROE for Hydro-Quebec.
- Prepared expert testimony and exhibits for return on equity analysis for numerous North American gas and electric utility clients. This included preparing direct testimony, responding to data requests, drafting rebuttal testimony in response to intervening witnesses, assisting with hearing preparation, and drafting post-hearing statements of position.

- Prepared expert testimony and exhibits for multiple clients seeking regulatory approval of mergers and acquisitions. This included summarizing credit rating agency reactions to the proposed mergers, researching merger approval standards, analyzing the benefits of increased financial scale in the utility industry, and developing financial and ring-fencing commitments in order to mitigate any risk that might result from the merger.
- Performed regulatory due diligence for clients considering the potential acquisition of a natural gas distribution company and an electric transmission company. Due diligence included a review of the regulatory framework in the jurisdiction of the target company, potential cost disallowances, an assessment of the projected ROE and capital structure, an evaluation of the reasonableness of projected capital spending based on forecasted economic growth in the service territory, and the implications of these factors on the value of the target company.
- Assisted in the development of a conservation program for New Jersey American Water, which was filed with the Board of Public Utilities in conjunction with the company's rate case. The program included rebates for various indoor and outdoor plumbing fixtures, as well as estimated penetration of the proposed rebate programs, and a cost/benefit analysis in support of the various rebates.
- Analyzed the internal policies and tariff of New Mexico Gas in response to service outages and determined if the time to restore service to customers was consistent with other major gas distribution outages that have occurred across the United States. Offered recommendations to improve the Company's communication with regulators and customers.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2008 – Present)
Assistant Vice President (2020)
Senior Project Manager (2013)
Project Manager (2010)
Senior Consultant

Colorado Public Utilities Commission (1999 – 2008)
Supervisory Financial Analyst, Telecommunications and Energy (2004)
Financial Analyst, Telecommunications, Energy and Water

State of Colorado, Division of Property Taxation (1994 – 1999)
Property Tax Specialist

Nobel Sysco, Inc. (1992 – 1994)
Marketing Associate

State of Colorado, Division of Property Taxation (1989 – 1991)
Tax Appraiser Consultant

EDUCATION

University of Colorado at Denver
M.S. in Business Administration, 1987
B.S. in Marketing (cum laude), 1986

EXPERT REPORTS

- Drafted a report for the Ontario Energy Board that reviewed low-income energy assistance programs that have been implemented in other jurisdictions, including Canada, the United States, the United Kingdom, the European Union countries, Australia, and New Zealand. Attended hearing and responded to questions related to research report on behalf of OEB staff.
- Drafted a report for the Ontario Energy Board that proposed revisions to the Board's existing rules for Demand Side Management for gas distribution companies in Ontario. Participated in workshop and responded to questions from stakeholders regarding the proposed changes to the Board's rules.

REGULATORY COMMISSION EXPERIENCE

- Supervised financial analysts and accountants in the energy and telecommunications units of the Colorado Public Utilities Commission from 2004 to 2008. In this capacity, he was responsible for the financial analysis, accounting, and auditing work of between five and nine financial analysts. This included preparation of expert testimony and recommendations concerning rate cases, applications for alternative forms of regulatory treatment, performance of managerial and financial audits, compliance with relevant statutes and Commission rules, and review of applications for certificates of public convenience and necessity, transfers of authority, franchise agreements, and discontinuance of service.
- Provided expert testimony on rate of return issues, capital structure, cost of debt, financial integrity, and credit quality in numerous rate case proceedings involving energy, telecommunications and water companies.
- Performed managerial and financial audits of regulated energy and telecommunications companies using the regulatory and accounting guidelines in the Uniform System of Accounts relied upon by the Federal Energy Regulatory Commission, the Federal Communications Commission, the Financial Accounting Standards Board, and the Commission's rules and regulations.
- Led Staff's review of an application for relaxed regulatory treatment by Qwest Corporation. Provided expert testimony regarding Qwest's market share in Colorado relative to cable providers, wireless providers, and Competitive Local Exchange Carriers. Assisted professional market research firm in designing questionnaire to examine customer preferences for purchasing telecommunications services, expectations concerning price and quality of those services, and desire for regulation over those services.

- Led Staff's investigation into a Competitive Local Exchange Carrier that was providing regulated telephone service to over 14,000 customers without the requisite Commission authority and without an effective tariff. This investigation resulted in a Commission order to cease and desist provision of regulated services, an order to transfer customers to an alternative provider, and sanctions against the principals.
- Administered the Colorado High Cost Support Mechanism, which provided universal telecommunications service to customers in rural, high costs areas through an assessment on all Colorado customers. Also, later supervised the position that administered this program.

PUBLICATIONS AND RESEARCH

- "Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with James Coyne), Public Utilities Fortnightly, May 2010

OTHER ACTIVITIES

- Member of 401(k) investment committee at Concentric Energy Advisors, Inc. since 2011.

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Alberta Utilities Commission				
ENMAX Power Corp.	2022	ENMAX Power Corp.	Application No. 27084	Cost of Capital
Beverage Container Management Board (Alberta)				
Beverage Container Management Board	2019	Beverage Container Management Board	N/A	Return margin for Alberta bottle depots
Colorado Public Utilities Commission				
Colorado PUC Staff	2000	Qwest Corporation	99A-577T	Capital Structure Cost of Capital Cost of Debt Composite Income Tax Rate Interest During Construction factor Ad Valorem Tax factor
Colorado PUC Staff	2001	Peetz Cooperative Telephone	01S-321T	Cost of Capital Revenue Requirement Adjustments to Rate Base Adjustment to Operating Expenses Imputed Capital Structure Capital Credit Rotation
Colorado PUC Staff	2002	Mile High Telecom	02C-082T	Order to show cause Operating without CPCN or tariff Violation of stipulation – alleged fraud
Colorado PUC Staff	2002	Public Service Company of Colorado – Electric/Gas	02S-315EG	Cost of Capital Dissolution of PS Credit Corporation Financial Integrity and credit ratings Impact of NRG on regulated entity Dividend payments and capital spending
Colorado PUC Staff	2003	Aquila Networks, Inc.	02S-594E	Cost of Capital
Colorado PUC Staff	2003	Lake Durango Water Company	03S-052W	Allowable expenses – depreciation and taxes Value of purchased water Operating Ratio method Rate design for retail and bulk customers Customer impact of proposed rates Enhancement of accounting & financial reports
Colorado PUC Staff	2003	Roggen Telephone	03S-246T	Cost of Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Colorado PUC Staff	2003	South Park Telephone	03A-277T	Request for HCSM support Adjustments to Rate Base Disallowance of Expenses Depreciation rates and USF impact Cost of Capital
Colorado PUC Staff	2003	Pine Drive Telephone	03S-314T	Cost of Capital
Colorado PUC Staff	2003	Phillips County Telephone	03S-315T	Cost of Capital
Colorado PUC Staff	2004	Aquila Networks, Inc.	04S-035E	Cost of Capital
Colorado PUC Staff	2004	SC TxLink, LLC	04A-508	CPCN for CLEC authority Financial Assurance - bonding
Colorado PUC Staff	2005	Qwest Corporation	04A-411T	History of CLEC competition since 1996 Wireless competition in Colorado Is Wireless substitute for wireline? Financial barriers to entry Introduce customer survey Analyze and interpret survey results Regulation of retail service in 14 states
Colorado PUC Staff	2005	Public Service Company of Colorado – Gas	05S-264G	Cost of Capital – investor owned Rate design issues in Phase 2 – S&F Charge Impact on rate of return – minimum system
Colorado PUC Staff	2005	Public Service Company of Colorado - Steam	05S-369ST	Cost of Capital
Colorado PUC Staff	2006	Public Service Company of Colorado - Electric	06S-234EG	Cost of Capital Credit quality and cash flow Financial integrity and credit ratings Purchased power and imputed debt Performance based regulatory plan
Colorado PUC Staff	2007	Public Service Company of Colorado - Gas	06S-656G	Cost of Capital Financial integrity and credit ratings
Colorado PUC Staff	2007	Nunn Telephone	07A-124T	Overview of HCSM statutes and rules Information required by CRS 40-15-208 Use of separation program – revenue requirement Challenges faced with new petition process

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Island Regulatory and Appeals Commission (Prince Edward Island)				
Maritime Electric Company	2018	Maritime Electric Company, Ltd.	UE20944	Cost of Capital
Maritime Electric Company	2022	Maritime Electric Company, Ltd.	UE20946	Cost of Capital
Montana Public Service Commission				
ABACO Energy Services, LLC	2020	ABACO Energy Services, LLC	D2020.07.08 2	Revenue Requirement, Rate Design, and Cost of Capital.
New Brunswick Energy and Utilities Board				
Liberty Utilities (Gas New Brunswick) LP	2021	Liberty Utilities (Gas New Brunswick) LP	491	Cost of Capital (Rebuttal)
New York Public Service Commission				
New York State Gas and Electric Company and Rochester Gas and Electric	2015	New York State Gas and Electric Company and Rochester Gas and Electric	15G-0284	Cost of Capital (Rebuttal)
Niagara Mohawk Power Corporation d/b/a National Grid	2017	Niagara Mohawk Power Corporation d/b/a National Grid	17-E-0238 17-G-0239	Cost of Capital (Rebuttal)
Pennsylvania Public Utility Commission				
Utilities, Inc.	2019	Community Utilities of Pennsylvania, Inc.	R-2019-3008947	Cost of Capital
Régie de l'Energie du Quebec				
Hydro Quebec Distribution and Hydro Quebec TransÉnergie	2013	Hydro Quebec Distribution and Hydro Quebec TransÉnergie	R-3842-2013	Risk analysis in support of ROE testimony
Vermont Public Utility Commission				
Vermont Gas Systems, Inc.	2019	Vermont Gas Systems	19-0513-TF	Cost of Equity
Yukon Utilities Board				
ATCO Electric Yukon	2023	ATCO Electric Yukon	Pending	Risk Premium above benchmark return on equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Subpoenas to Provide Expert Testimony				
U.S. Bankruptcy Court – Denver, CO	2005	ON Systems, Inc.	N/A	Testify in U.S. bankruptcy court - value of CPCN for local exchange telecom service
U.S. District Court, Southern District of Florida	2008	USA vs. Wetherald, et al	06-80199-CR-MARRA	Testify on behalf of U.S. government Wire fraud, mail fraud, money laundering

ROE Results - Four Model Average

	Canadian	U.S. Electric	North American Electric
Constant Growth DCF	10.03%	10.44%	10.07%
Multi-stage DCF	10.18%	9.38%	9.42%
CAPM - average MRP	10.09%	10.68%	10.37%
Risk Premium		10.26%	10.26%
MEAN	10.10%	10.19%	10.03%

ROE Results - Excluding Constant DCF and CAPM with Historical MRP

	Canadian	U.S. Electric	North American Electric
Multi-stage DCF	10.18%	9.38%	9.42%
CAPM - historical MRP	9.57%	10.15%	9.86%
Risk Premium		10.26%	10.26%
MEAN	9.87%	9.93%	9.85%

Canadian & U.S. Macroeconomic Factors

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[11]	[12]	[13]	[14]
	Total Return on:		Total Return on:		Real GDP Growth		CPI Change		10-year Gov't Bond		Exports		Unemployment		Currency
	S&P/TSX	S&P 500	S&P/TSX Utilities	S&P 500 Utilities	Canada	U.S.	Canada	U.S.	Canada	U.S.	Canada to U.S./ Canadian GDP	U.S. to Canada / U.S. GDP	Canada	U.S.	Exchange Rate (CAD / USD)
1990	-18.7	-4.9	-1.6	-1.4	0.2	2.7	4.8	5.4	10.7	8.5		1.4	8.2	5.6	1.17
1991	8.4	31.9	-3.5	25.0	-2.1	-0.4	5.6	4.2	9.5	7.9		1.4	10.3	6.9	1.15
1992	-4.1	7.6	2.1	7.2	0.9	3.2	1.5	3.0	8.1	7.0		1.4	11.2	7.5	1.21
1993	32.2	10.1	16.3	13.4	2.7	3.4	1.9	3.0	7.2	5.9		1.5	11.4	6.9	1.29
1994	-1.3	1.2	3.8	-11.1	4.5	4.1	0.2	2.6	8.4	7.1		1.6	10.4	6.1	1.37
1995	15.1	37.6	-2.0	32.0	2.7	2.9	2.1	2.8	8.2	6.6		1.7	9.5	5.6	1.37
1996	26.7	22.0	17.5	5.2	1.6	3.4	1.6	3.0	7.2	6.4		1.7	9.6	5.4	1.36
1997	15.3	34.0	32.1	25.7	4.3	3.6	1.6	2.3	6.1	6.3	26.7	1.8	9.1	4.9	1.38
1998	-2.0	27.9	-0.2	15.3	3.9	4.4	1.0	1.6	5.3	5.3	28.6	1.7	8.3	4.5	1.48
1999	30.4	21.1	-30.8	-9.2	5.2	5.7	1.7	2.2	5.6	5.6	30.6	1.7	7.6	4.2	1.49
2000	10.1	-4.6	42.1	61.2	5.2	5.7	2.7	3.4	5.9	6.0	32.3	1.7	6.8	4.0	1.49
2001	-9.3	-9.3	7.3	-27.8	1.8	3.2	2.5	2.8	5.5	5.0	30.6	1.5	7.2	4.7	1.55
2002	-11.9	-22.6	3.4	-30.9	3.0	2.4	2.3	1.6	5.3	4.6	29.0	1.5	7.7	5.8	1.57
2003	24.2	24.5	23.4	23.3	1.8	2.3	2.8	2.3	4.8	4.0	26.1	1.5	7.6	6.0	1.40
2004	13.4	11.2	8.7	24.3	3.1	4.2	1.9	2.7	4.6	4.3	26.1	1.6	7.2	5.5	1.30
2005	25.4	7.0	37.6	19.2	3.2	3.5	2.2	3.4	4.1	4.3	25.8	1.6	6.8	5.1	1.21
2006	15.5	13.9	5.8	18.7	2.6	3.2	2.0	3.2	4.2	4.8	24.1	1.7	6.5	4.6	1.13
2007	11.6	5.7	11.8	18.9	2.1	2.8	2.1	2.8	4.3	4.6	22.5	1.7	6.2	4.6	1.07
2008	-33.5	-36.1	-20.4	-28.0	1.0	1.2	2.4	3.8	3.6	3.6	22.3	1.8	6.3	5.8	1.07
2009	31.3	22.6	15.9	9.4	-2.9	-1.6	0.3	-0.4	3.2	3.2	17.2	1.4	8.5	9.3	1.14
2010	16.3	13.2	18.6	5.2	3.1	0.6	1.8	1.6	3.2	3.2	17.7	1.7	8.1	9.6	1.03
2011	-8.5	1.1	6.0	18.7	3.1	2.6	2.9	3.2	2.8	2.8	18.6	1.8	7.6	8.9	0.99
2012	4.9	14.2	3.3	3.0	1.8	1.3	1.5	2.1	1.9	1.8	18.4	1.8	7.4	8.1	1.00
2013	12.0	29.1	-4.9	11.2	2.3	1.3	0.9	1.5	2.3	2.3	18.8	1.8	7.2	7.4	1.03
2014	10.7	14.7	16.2	31.0	2.9	1.7	1.9	1.6	2.2	2.5	20.1	1.8	7.0	6.2	1.10
2015	-9.2	1.4	-4.4	-5.4	0.7	3.7	1.1	0.1	1.5	2.1	19.9	1.5	7.0	5.3	1.28
2016	21.9	13.7	18.7	16.6	1.0	2.7	1.4	1.3	1.3	1.8	19.4	1.4	7.0	4.9	1.33
2017	8.3	20.8	10.9	9.1	3.0	2.3	1.6	2.1	1.8	2.3	19.2	1.4	6.4	4.5	1.30
2018	-8.9	-4.4	-8.9	4.1	2.8	2.8	2.3	2.4	2.3	2.9	19.4	1.5	5.9	4.0	1.30
2019	23.5	31.8	38.2	25.7	1.9	1.9	1.9	1.8	1.6	2.1	19.3	1.4	5.7	3.8	1.33
2020	5.6	18.4	15.3	0.5	-5.1	0.5	0.7	1.2	0.8	0.9	17.0	1.2	9.7	8.4	1.34
2021	25.2	28.7	11.6	17.7	5.0	2.8	3.4	4.7	1.4	1.4	19.0	1.6	7.5	5.4	1.25
2022	-5.8	-18.6	-10.6	2.5	3.4	4.8	6.8	8.0	2.8	3.0	n/a	1.8	5.3	3.6	1.30
25-year Avg.	8.05	9.02	8.58	9.38	2.23	2.65	2.09	2.44	3.29	3.38	22.58	1.61	7.13	5.76	1.26
10-year Avg.	8.32	13.55	8.21	11.30	1.79	2.46	2.21	2.48	1.79	2.15	19.12	1.54	6.87	5.33	1.26
5-year Avg.	7.92	11.17	9.13	10.11	1.61	2.56	3.03	3.64	1.77	2.06	18.67	1.48	6.81	5.04	1.30
Correlation	0.72		0.58		0.72		0.85		0.98		0.24		0.49		--
					Consensus Forecasts [15]										
2024					1.30	0.70	2.20	2.60	3.00	3.50					
2025					2.40	2.20	2.10	2.20	3.20	3.40					
2026					2.20	2.20	2.00	2.20	3.20	3.40					

Notes:
[1] Source: Bloomberg Professional; total return index gross dividend yield
[2] Source: Bloomberg Professional; total return index gross dividend yield
[3] Source: Bloomberg Professional; total return index gross dividend yield
[4] Source: Bloomberg Professional; total return index gross dividend yield
[5] Source: Statistics Canada. Table 36-10-0104-01 Gross domestic product, expenditure-based, Canada updated July 2023
[6] Source: Bureau of Economic Analysis, Table 1.1.5. Gross Domestic Product, updated July 2023
[7] Source: Statistics Canada; Consumer Price Index (2002=100), All items, not seasonally adjusted, accessed July 26, 2023
[8] Source: U.S. Bureau of Labor Statistics; CPI-All Urban Consumers (1982-84=100), all items, not seasonally adjusted, accessed July 26, 2023
[9] Source: Bank of Canada, updated July 26, 2023
[10] Source: Bloomberg Professional
[11] Source: Statistics Canada, Imports, exports and trade balance of goods by country and Gross domestic product, expenditure-based; updated July 26, 2023
United States Census Bureau (https://www.census.gov/foreign-trade/balance/c1220.html); Bureau of Economic Analysis; Table 1.1.5
[12] Source: Statistics Canada; Labour force survey estimates (LFS), unemployment rate, 15 years and over, seasonally adjusted, accessed July 26, 2023
[13] Source: U.S. Bureau of Labor Statistics, Unemployment Rate, seasonally adjusted, accessed July 26, 2023
[14] Source: Federal Reserve Economic Data, as of July 26, 2023
[15] Source: Consensus Forecasts, Survey Date April 11, 2023

CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	S&P Rating	Pays Dividends (Yes/No)	Positive Earnings Growth by more than one Analyst (Yes/No)	Market Cap (C$ Million)	Total Electric Customers	Total Revenue (C$ Million)	Total Assets (C$ Million)	Regulated Income / Total Income (%)	Regulated Electric Income / Total Regulated Income (%)	Involved in Merger (Yes/No)
Algonquin Power and Utilities	AQN	BBB	No	Yes	6,637	305,700	3,600	23,858	94%	N/A	No
AltaGas Inc.	ALA	BBB-	Yes	No	7,598	1,700,000	14,087	23,965	41%	N/A	No
Canadian Utilities Limited	CU	NR	Yes	No	8,522	262,578	4,048	21,974	105%	N/A	No
Emera Inc.	EMA	BBB	Yes	Yes	14,132	1,520,000	7,588	39,742	101%	N/A	No
Enbridge Inc.	ENB	BBB+	Yes	Yes	100,253	NA	53,309	179,608	15%	N/A	No
Hydro One, Ltd.	H	A-	Yes	Yes	22,328	1,492,404	7,780	31,457	102%	N/A	No

Notes:
[1] Source: S&P Capital IQ, as of 8/31/2023
[2] Source: Bloomberg Professional
[3] Source: Value Line, Zacks and Yahoo Finance
[4] Source: S&P Capital IQ, as of 9/18/2023
[5] Source: S&P Capital IQ, as of 9/18/2023
[6] Source: S&P Capital IQ, as of 9/18/2023
[4] Source: S&P Capital IQ, as of 9/18/2023
[8] Source: Company 10-K reports, average of three most recent years
[9] Source: Company 10-K reports, average of three most recent years
[10] Source: Bloomberg Professional

U.S. ELECTRIC PROXY GROUP

Company	Ticker	S&P Rating [1]	Pays Dividends (Yes/No) [2]	Positive Earnings Growth by more than one Analyst (Yes/No) [3]	Market Cap (US$ Million) [4]	Total Electric Customers [5]	Total Revenue ($ Million) [6]	Total Assets ($ Million) [7]	Regulated Income / Total Income (%) [8]	Regulated Electric Income / Total Regulated Income (%) [9]	Involved in Merger (Yes/No) [10]
Alliant Energy Corporation	LNT	A-	Yes	Yes	13,135	989,369	4,205	20,163	98%	91%	No
American Electric Power Company, Inc.	AEP	A-	Yes	Yes	41,111	5,600,000	19,640	93,469	96%	100%	No
Duke Energy Corporation	DUK	BBB+	Yes	Yes	72,793	8,244,161	28,319	178,086	100%	90%	No
Entergy Corporation	ETR	BBB+	Yes	Yes	20,654	3,002,068	13,764	58,595	94%	99%	No
Evergy Inc	EVRG	A-	Yes	Yes	12,445	1,652,200	5,859	29,490	100%	100%	No
Eversource Energy	ES	A-	Yes	Yes	22,244	3,285,000	12,289	53,231	100%	85%	No
NextEra Energy Inc	NEE	A-	Yes	Yes	137,694	NA	20,956	158,935	79%	100%	No
OGE Corp	OGE	BBB+	Yes	Yes	7,134	888,759	3,376	12,545	100%	100%	No
Pinnacle West Capital Corporation	PNW	BBB+	Yes	Yes	8,933	1,356,195	4,324	22,723	100%	100%	No
Portland General Electric Company	POR	BBB+	Yes	Yes	4,473	926,000	2,647	10,459	100%	100%	No
Average									97%	97%	

Notes:
[1] Source: S&P Capital IQ
[2] Source: Bloomberg Professional
[3] Source: Value Line, Zacks and Yahoo Finance
[4] Source: S&P Capital IQ, as of 9/18/2023
[5] Source: S&P Capital IQ, as of 9/18/2023
[6] Source: S&P Capital IQ, as of 9/18/2023
[7] Source: S&P Capital IQ, as of 9/18/2023
[8] - [9] Source: Company 10-K reports, average of three most recent years
[10] Source: Bloomberg Professional

NORTH AMERICA ELECTRIC PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	S&P Rating	Pays Dividends (Yes/No)	Postive Earnings Growth by more than one Analyst (Yes/No)	Market Cap ($ Million)	Total Electric Customers	Total Revenue ($ Million)	Total Assets ($ Million)	Regulated Income / Total Income (%)	Regulated Electric Income / Total Regulated Income (%)	Involved in Merger (Yes/No)
Algonquin Power and Utilities	AQN	BBB	No	Yes	6,637	305,700	3,600	23,858	94%	N/A	No
Canadian Utilities Limited	CU	NR	Yes	No	8,522	262,578	4,048	21,974	105%	N/A	No
Emera Inc.	EMA	BBB	Yes	Yes	14,132	1,520,000	7,588	39,742	101%	N/A	No
Hydro One, Ltd.	H	A-	Yes	Yes	22,328	1,492,404	7,780	31,457	102%	N/A	No
Alliant Energy Corporation	LNT	A-	Yes	Yes	13,135	989,369	4,205	20,163	98%	91%	No
American Electric Power Company, Inc.	AEP	A-	Yes	Yes	41,111	5,600,000	19,640	93,469	96%	100%	No
Duke Energy Corporation	DUK	BBB+	Yes	Yes	72,793	8,244,161	28,319	178,086	100%	90%	No
Entergy Corporation	ETR	BBB+	Yes	Yes	20,654	3,002,068	13,764	58,595	94%	99%	No
Evergy Inc	EVRG	A-	Yes	Yes	12,445	1,652,200	5,859	29,490	100%	100%	No
Eversource Energy	ES	A-	Yes	Yes	22,244	3,285,000	12,289	53,231	100%	85%	No
NextEra Energy Inc	NEE	A-	Yes	Yes	137,694	NA	20,956	158,935	79%	100%	No
OGE Corp	OGE	BBB+	Yes	Yes	7,134	888,759	3,376	12,545	100%	100%	No
Pinnacle West Capital Corporation	PNW	BBB+	Yes	Yes	8,933	1,356,195	4,324	22,723	100%	100%	No
Portland General Electric Company	POR	BBB+	Yes	Yes	4,473	926,000	2,647	10,459	100%	100%	No

Notes:
[1] Source: S&P Capital IQ
[2] Source: Bloomberg Professional
[3] Source: Value Line, Zacks and Yahoo Finance
[4] Source: S&P Capital IQ, as of 9/18/2023
[5] Source: S&P Capital IQ, as of 9/18/2023
[6] Source: S&P Capital IQ, as of 9/18/2023
[7] Source: S&P Capital IQ, as of 9/18/2023
[8] Source: Company 10-K reports, average of three most recent years
[9] Source: Company 10-K reports, average of three most recent years
[10] Source: Bloomberg Professional

90-DAY CONSTANT GROWTH DCF -- CANADIAN PROXY GROUP

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks EPS Growth	[6] SNL EPS Growth	[7] Value Line EPS Growth	[8] First Call Growth	[9] Average Growth Rate	[10] Low DCF ROE	[11] Mean DCF ROE	[12] High DCF ROE
Algonquin Power & Utilities Corp.	AQN	$0.43	$8.17	5.31%	5.36%	3.00%	Negative	n/a	0.41%	1.71%	5.73%	7.06%	8.39%
AltaGas Ltd.	ALA	$1.12	$24.43	4.58%	4.71%	n/a	6.00%	n/a	4.65%	5.33%	9.34%	10.03%	10.72%
Canadian Utilities Limited	CU	$1.79	$35.04	5.12%	5.16%	n/a	1.00%	n/a	1.92%	1.46%	6.15%	6.62%	7.09%
Emera Inc.	EMA	$2.76	$54.61	5.05%	5.23%	n/a	4.10%	13.00%	3.49%	6.86%	8.63%	12.09%	18.38%
Enbridge Inc.	ENB	$3.55	$49.42	7.18%	7.37%	6.00%	2.00%	10.00%	2.87%	5.22%	9.26%	12.59%	17.54%
Hydro One Ltd.	H	$1.19	$37.73	3.14%	3.23%	n/a	5.80%	n/a	5.33%	5.57%	8.56%	8.80%	9.03%
MEAN				5.07%	5.18%	4.50%	3.78%	11.50%	3.11%	4.36%	7.94%	9.53%	11.86%
Flotation Costs [13]											0.50%	0.50%	0.50%
											8.44%	10.03%	12.36%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2023
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [10])
[5] Source: Zacks at August 31, 2023
[6] Source: SNL Financial Median Long-Term EPS Growth Rate as of August 31, 2023
[7] Source: Value Line
[8] Yahoo! Finance as of August 31, 2023
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])
[13] The Board allows 50 bps flotation costs and financial flexibility.

90-DAY CONSTANT GROWTH DCF -- U.S. ELECTRIC PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Alliant Energy Corporation	LNT	$1.81	$52.86	3.42%	3.54%	6.50%	6.00%	6.50%	7.00%	6.50%	9.53%	10.04%	10.54%
American Electric Power Company, Inc.	AEP	$3.32	$84.88	3.91%	4.02%	5.60%	6.00%	6.00%	5.20%	5.70%	9.21%	9.72%	10.03%
Duke Energy Corporation	DUK	$4.10	$92.45	4.43%	4.56%	6.10%	6.09%	5.00%	5.95%	5.79%	9.55%	10.35%	10.67%
Entergy Corporation	ETR	$4.28	$100.24	4.27%	4.37%	5.70%	6.90%	0.50%	6.60%	4.93%	4.78%	9.30%	11.32%
Evergy, Inc.	EVRG	$2.45	$59.17	4.14%	4.25%	5.20%	5.40%	7.50%	2.67%	5.19%	6.87%	9.44%	11.80%
Eversource Energy	ES	$2.70	$70.98	3.80%	3.92%	5.70%	6.05%	6.50%	6.70%	6.24%	9.61%	10.16%	10.63%
NextEra Energy Inc.	NEE	$1.87	$72.90	2.57%	2.68%	8.40%	8.75%	9.50%	8.80%	8.86%	11.07%	11.54%	12.19%
OGE Corp.	OGE	$1.66	$35.8750	4.63%	4.73%	3.70%	2.80%	6.50%	negative	4.33%	7.49%	9.06%	11.28%
Pinnacle West Capital Corporation	PNW	$3.46	$80.17	4.32%	4.43%	6.50%	6.48%	2.50%	6.10%	5.40%	6.87%	9.83%	10.96%
Portland General Electric Company	POR	$1.90	$47.87	3.97%	4.09%	6.00%	6.80%	5.00%	5.90%	5.93%	9.07%	10.01%	10.90%
MEAN				3.95%	4.06%	5.94%	6.13%	5.55%	6.10%	5.89%	8.40%	9.94%	11.03%
Flotation Costs [13]											0.50%	0.50%	0.50%
											8.90%	10.44%	11.53%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2023
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [10])
[5] Source: Zacks at August 31, 2023
[6] Source: SNL Financial Median Long-Term EPS Growth Rate as of August 31, 2023
[7] Source: Value Line
[8] Yahoo! Finance as of August 31, 2023
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])
[13] The Board allows 50 bps flotation costs and financial flexibility.

90-DAY CONSTANT GROWTH DCF -- NORTH AMERICAN ELECTRIC PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Algonquin Power & Utilities Corp.	AQN	$0.43	$8.17	5.31%	5.36%	3.00%	Negative	n/a	0.41%	1.71%	5.73%	7.06%	8.39%
Canadian Utilities Limited	CU	$1.79	$35.04	5.12%	5.16%	n/a	1.00%	n/a	1.92%	1.46%	6.15%	6.62%	7.09%
Emera Inc.	EMA	$2.76	$54.61	5.05%	5.23%	n/a	4.10%	13.00%	3.49%	6.86%	8.63%	12.09%	18.38%
Hydro One Ltd.	H	$1.19	$37.73	3.14%	3.23%	n/a	5.80%	n/a	5.33%	5.57%	8.56%	8.80%	9.03%
Alliant Energy Corporation	LNT	$1.81	$52.86	3.42%	3.54%	6.50%	6.00%	6.50%	7.00%	6.50%	9.53%	10.04%	10.54%
American Electric Power Company, Inc.	AEP	$3.32	$84.88	3.91%	4.02%	5.60%	6.00%	6.00%	5.20%	5.70%	9.21%	9.72%	10.03%
Duke Energy Corporation	DUK	$4.10	$92.45	4.43%	4.56%	6.10%	6.09%	5.00%	5.95%	5.79%	9.55%	10.35%	10.67%
Entergy Corporation	ETR	$4.28	$100.24	4.27%	4.37%	5.70%	6.90%	0.50%	6.60%	4.93%	4.78%	9.30%	11.32%
Evergy, Inc.	EVRG	$2.45	$59.17	4.14%	4.25%	5.20%	5.40%	7.50%	2.67%	5.19%	6.87%	9.44%	11.80%
Eversource Energy	ES	$2.70	$70.98	3.80%	3.92%	5.70%	6.05%	6.50%	6.70%	6.24%	9.61%	10.16%	10.63%
NextEra Energy Inc.	NEE	$1.87	$72.90	2.57%	2.68%	8.40%	8.75%	9.50%	8.80%	8.86%	11.07%	11.54%	12.19%
OGE Corp.	OGE	$1.66	$35.88	4.63%	4.73%	3.70%	2.80%	6.50%	negative	4.33%	7.49%	9.06%	11.28%
Pinnacle West Capital Corporation	PNW	$3.46	$80.17	4.32%	4.43%	6.50%	6.48%	2.50%	6.10%	5.40%	6.87%	9.83%	10.96%
Portland General Electric Company	POR	$1.90	$47.87	3.97%	4.09%	6.00%	6.80%	5.00%	5.90%	5.93%	9.07%	10.01%	10.90%
MEAN				4.15%	4.25%	5.67%	5.55%	6.23%	5.08%	5.32%	8.08%	9.57%	10.94%
Flotation Costs [13]											0.50%	0.50%	0.50%
											8.58%	10.07%	11.44%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2023
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [10])
[5] Source: Zacks at August 31, 2023
[6] Source: SNL Financial Median Long-Term EPS Growth Rate as of August 31, 2023
[7] Source: Value Line
[8] Yahoo! Finance as of August 31, 2023
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])
[13] The Board allows 50 bps flotation costs and financial flexibility.

90-DAY MULTI-STAGE DCF -- CANADIAN PROXY GROUP

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Growth Rate, Years 1-5	[4] Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] GDP Growth (perpetuity)	[10] ROE
Algonquin Power & Utilities Corp.	AQN	$0.43	$8.17	1.71%	2.09%	2.48%	2.87%	3.26%	3.65%	4.04%	9.03%
AltaGas Ltd.	ALA	$1.12	$24.43	5.33%	5.11%	4.90%	4.68%	4.47%	4.25%	4.04%	9.43%
Canadian Utilities Limited	CU	$1.79	$35.04	1.46%	1.89%	2.32%	2.75%	3.18%	3.61%	4.04%	8.76%
Emera Inc.	EMA	$2.76	$54.61	6.86%	6.39%	5.92%	5.45%	4.98%	4.51%	4.04%	10.56%
Enbridge Inc.	ENB	$3.55	$49.42	5.22%	5.02%	4.82%	4.63%	4.43%	4.24%	4.04%	12.50%
Hydro One Ltd.	H	$1.19	$37.73	5.57%	5.31%	5.06%	4.80%	4.55%	4.29%	4.04%	7.77%
MEAN				4.36%	4.30%	4.25%	4.20%	4.15%	4.09%	4.04%	9.68%
Flotation Costs [11]											0.50%
											10.18%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2023
[3] Source: Constant Growth DCF
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, April 11, 2023, at 28 estimates for 2029-2033 = (GDP x (1+ CPI))+CPI
[10] Internal rate of return
[13] The Board allows 50 bps flotation costs and financial flexibility.

90-DAY MULTI-STAGE DCF -- U.S. ELECTRIC PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Alliant Energy Corporation	LNT	$1.81	$52.86	6.50%	6.11%	5.71%	5.32%	4.93%	4.53%	4.14%	8.44%
American Electric Power Company, Inc.	AEP	$3.32	$84.88	5.70%	5.44%	5.18%	4.92%	4.66%	4.40%	4.14%	8.82%
Duke Energy Corporation	DUK	$4.10	$92.45	5.79%	5.51%	5.24%	4.96%	4.69%	4.42%	4.14%	9.48%
Entergy Corporation	ETR	$4.28	$100.24	4.93%	4.79%	4.66%	4.53%	4.40%	4.27%	4.14%	9.01%
Evergy, Inc.	EVRG	$2.45	$59.17	5.19%	5.02%	4.84%	4.67%	4.49%	4.32%	4.14%	8.94%
Eversource Energy	ES	$2.70	$70.98	6.24%	5.89%	5.54%	5.19%	4.84%	4.49%	4.14%	8.84%
NextEra Energy Inc.	NEE	$1.87	$72.90	8.86%	8.08%	7.29%	6.50%	5.72%	4.93%	4.14%	7.88%
OGE Corp.	OGE	$1.66	$35.88	4.33%	4.30%	4.27%	4.24%	4.21%	4.17%	4.14%	9.23%
Pinnacle West Capital Corporation	PNW	$3.46	$80.17	5.40%	5.19%	4.98%	4.77%	4.56%	4.35%	4.14%	9.21%
Portland General Electric Company	POR	$1.90	$47.87	5.93%	5.63%	5.33%	5.03%	4.74%	4.44%	4.14%	8.95%
MEAN				5.89%	5.59%	5.30%	5.01%	4.72%	4.43%	4.14%	8.88%
Flotation Costs [11]											0.50%
											9.38%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2023
[3] Source: Constant Growth DCF
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, April 11, 2023, at 3, estimates for 2029-2033 = (GDP x (1+ CPI))+CPI
[10] Internal rate of return
[13] The Board allows 50 bps flotation costs and financial flexibility.

90-DAY MULTI-STAGE DCF -- NORTH AMERICAN ELECTRIC PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Algonquin Power & Utilities Corp.	AQN	$0.43	$8.17	1.71%	2.09%	2.48%	2.87%	3.26%	3.65%	4.04%	9.03%
Canadian Utilities Limited	CU	$1.79	$35.04	1.46%	1.89%	2.32%	2.75%	3.18%	3.61%	4.04%	8.76%
Emera Inc.	EMA	$2.76	$54.61	6.86%	6.39%	5.92%	5.45%	4.98%	4.51%	4.04%	10.56%
Hydro One Ltd.	H	$1.19	$37.73	5.57%	5.31%	5.06%	4.80%	4.55%	4.29%	4.04%	7.77%
Alliant Energy Corporation	LNT	$1.81	$52.86	6.50%	6.11%	5.71%	5.32%	4.93%	4.53%	4.14%	8.44%
American Electric Power Company, Inc.	AEP	$3.32	$84.88	5.70%	5.44%	5.18%	4.92%	4.66%	4.40%	4.14%	8.82%
Duke Energy Corporation	DUK	$4.10	$92.45	5.79%	5.51%	5.24%	4.96%	4.69%	4.42%	4.14%	9.48%
Entergy Corporation	ETR	$4.28	$100.24	4.93%	4.79%	4.66%	4.53%	4.40%	4.27%	4.14%	9.01%
Evergy, Inc.	EVRG	$2.45	$59.17	5.19%	5.02%	4.84%	4.67%	4.49%	4.32%	4.14%	8.94%
Eversource Energy	ES	$2.70	$70.98	6.24%	5.89%	5.54%	5.19%	4.84%	4.49%	4.14%	8.84%
NextEra Energy Inc.	NEE	$1.87	$72.90	8.86%	8.08%	7.29%	6.50%	5.72%	4.93%	4.14%	7.88%
OGE Corp.	OGE	$1.66	$35.88	4.33%	4.30%	4.27%	4.24%	4.21%	4.17%	4.14%	9.23%
Pinnacle West Capital Corporation	PNW	$3.46	$80.17	5.40%	5.19%	4.98%	4.77%	4.56%	4.35%	4.14%	9.21%
Portland General Electric Company	POR	$1.90	$47.87	5.93%	5.63%	5.33%	5.03%	4.74%	4.44%	4.14%	8.95%
MEAN				5.32%	5.12%	4.92%	4.72%	4.51%	4.31%	4.11%	8.92%
Flotation Costs [11]											0.50%
											9.42%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2023
[3] Source: Constant Growth DCF
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, April 11, 2023, at (3, 28), estimates for 2029-2033 = (GDP x (1+ CPI))+CPI
[10] Internal rate of return
[13] The Board allows 50 bps flotation costs and financial flexibility.

Canadian Market DCF Calculation as of August 31, 2023

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast Canadian Government Bond 30 Year	Equity Risk Premium
S&P/TSX COMPOSITE INDEX	**3.74%**	**3.83%**	**4.53%**	**8.36%**	**3.52%**	**4.85%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Sun Life Financial Inc	SLF	587.1	65.91	Excl.	Excl.	4.6%	n/a		
Capstone Copper Corp	CS	694.6	6.29	Excl.	Excl.	n/a	n/a		
Enghouse Systems Ltd	ENGH	55.3	30.65	Excl.	Excl.	2.87%	n/a		
H&R Real Estate Investment Trust	HR-U	274.7	10.34	Excl.	Excl.	5.80%	n/a		
Ivanhoe Mines Ltd	IVN	1218.7	12.02	Excl.	Excl.	n/a	20.95%		
Sleep Country Canada Holdings Inc	ZZZ	34.8	24.74	Excl.	Excl.	3.83%	n/a		
West Fraser Timber Co Ltd	WFG	81.3	102.14	8,301	0.45%	1.56%	-13.30%	0.0069%	-0.0594%
TELUS International CDA Inc	TIXT	73.7	11.87	Excl.	Excl.	n/a	1.60%		
Brookfield Corp	BN	1563.2	46.12	Excl.	Excl.	0.82%	n/a		
Ballard Power Systems Inc	BLDP	298.7	5.69	Excl.	Excl.	n/a	47.00%		
Energy Fuels Inc/Canada	EFR	158.2	9.63	Excl.	Excl.	n/a	n/a		
Saputo Inc	SAP	422.6	29.21	Excl.	Excl.	2.53%	n/a		
Pembina Pipeline Corp	PPL	549.2	42	23,066	1.24%	6.36%	4.00%	0.0789%	0.0496%
Secure Energy Services Inc	SES	293.6	7.48	Excl.	Excl.	5.35%	n/a		
Gildan Activewear Inc	GIL	175.7	40.3	Excl.	Excl.	2.50%	n/a		
Descartes Systems Group Inc/The	DSG	85.0	101.31	Excl.	Excl.	n/a	n/a		
Nuvei Corp	NVEI	63.0	24.39	1,536	0.08%	2.22%	15.02%	0.0018%	0.0124%
Richelieu Hardware Ltd	RCH	55.9	43.31	Excl.	Excl.	1.39%	n/a		
Lithium Americas Corp	LAC	159.9	24.77	Excl.	Excl.	n/a	n/a		
Innergex Renewable Energy Inc	INE	204.3	12.89	Excl.	Excl.	5.59%	n/a		
Manulife Financial Corp	MFC	1828.7	24.98	45,682	2.46%	5.84%	0.60%	0.1436%	0.0147%
Element Fleet Management Corp	EFN	389.6	20.77	Excl.	Excl.	1.93%	n/a		
FirstService Corp	FSV	44.6	204.33	Excl.	Excl.	0.58%	n/a		
Canadian Pacific Kansas City Ltd	CP	931.5	107.26	99,910	5.37%	0.71%	7.00%	0.0381%	0.3761%
Lundin Gold Inc	LUG	237.5	16.2	Excl.	Excl.	3.34%	n/a		
Baytex Energy Corp	BTE	857.3	5.5	Excl.	Excl.	1.64%	n/a		
Crescent Point Energy Corp	CPG	535.9	11.12	Excl.	Excl.	3.60%	n/a		
Tricon Residential Inc	TCN	273.0	11.46	Excl.	Excl.	2.73%	n/a		
Sienna Senior Living Inc	SIA	73.0	11.74	Excl.	Excl.	7.97%	n/a		
Centerra Gold Inc	CG	217.1	8.11	1,761	0.09%	3.45%	60.25%	0.0033%	0.0570%
Intact Financial Corp	IFC	175.3	190.5	33,386	1.80%	2.31%	9.74%	0.0415%	0.1749%
Filo Corp	FIL	130.7	21.27	Excl.	Excl.	n/a	n/a		
George Weston Ltd	WN	137.2	149.85	Excl.	Excl.	1.90%	n/a		
iA Financial Corp Inc	IAG	102.5	84.77	Excl.	Excl.	3.61%	n/a		
MEG Energy Corp	MEG	285.4	24.17	Excl.	Excl.	n/a	n/a		
Hydro One Ltd	H	599.1	35.12	Excl.	Excl.	3.38%	n/a		
PrairieSky Royalty Ltd	PSK	239.0	25.85	Excl.	Excl.	3.71%	n/a		
Cameco Corp	CCO	433.3	50	Excl.	Excl.	n/a	57.26%		
Tilray Brands Inc	TLRY	703.3	3.98	Excl.	Excl.	n/a	n/a		
Canfor Corp	CFP	120.1	20.78	Excl.	Excl.	n/a	n/a		
Nutrien Ltd	NTR	494.5	85.59	42,325	2.28%	3.34%	13.40%	0.0760%	0.3050%
TransAlta Renewables Inc	RNW	266.9	13.15	Excl.	Excl.	7.15%	n/a		
Interfor Corp	IFP	51.4	22.8	Excl.	Excl.	n/a	n/a		
Primo Water Corp	PRMW	160.8	20.62	Excl.	Excl.	2.10%	n/a		
Brookfield Infrastructure Partners LP	BIP-U	458.3	42.97	Excl.	Excl.	4.82%	n/a		
Winpak Ltd	WPK	65.0	39.95	Excl.	Excl.	0.30%	n/a		
Franco-Nevada Corp	FNV	192.1	194.66	37,386	2.01%	0.95%	4.00%	0.0190%	0.0804%
Cenovus Energy Inc	CVE	1896.4	26.94	Excl.	Excl.	2.08%	n/a		
Athabasca Oil Corp	ATH	581.2	3.75	Excl.	Excl.	n/a	n/a		
NorthWest Healthcare Properties Real Estate Inves	NWH-U	241.6	6.83	Excl.	Excl.	11.71%	n/a		
Sprott Inc	SII	25.9	44.94	Excl.	Excl.	3.01%	n/a		
Empire Co Ltd	EMP/A	155.2	35.2	5,462	0.29%	2.07%	0.13%	0.0061%	0.0004%
Loblaw Cos Ltd	L	316.9	117.33	37,185	2.00%	1.52%	1.73%	0.0304%	0.0346%
Metro Inc/CN	MRU	230.0	69.64	Excl.	Excl.	1.74%	n/a		
Tourmaline Oil Corp	TOU	339.8	69.29	Excl.	Excl.	1.50%	n/a		
Bank of Montreal	BMO	716.9	116.37	83,421	4.49%	5.05%	0.40%	0.2267%	0.0179%

Canadian Market DCF Calculation as of August 31, 2023

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast Canadian Government Bond 30 Year	Equity Risk Premium
S&P/TSX COMPOSITE INDEX	**3.74%**	**3.83%**	**4.53%**	**8.36%**	**3.52%**	**4.85%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Bank of Nova Scotia/The	BNS	1205.3	64.12	77,286	4.16%	6.61%	-2.79%	0.2748%	-0.1160%
NexGen Energy Ltd	NXE	491.4	7.11	Excl.	Excl.	n/a	n/a		
Canadian Imperial Bank of Commerce	CM	924.1	53.54	49,475	2.66%	6.50%	1.04%	0.1729%	0.0277%
Canadian Western Bank	CWB	96.4	26.29	Excl.	Excl.	5.02%	n/a		
Laurentian Bank of Canada	LB	43.5	36.75	Excl.	Excl.	5.12%	n/a		
National Bank of Canada	NA	338.0	94.17	Excl.	Excl.	4.33%	n/a		
Toronto-Dominion Bank/The	TD	1827.5	82.42	150,619	8.10%	4.66%	2.87%	0.3774%	0.2325%
EQB Inc	EQB	37.7	77.79	Excl.	Excl.	1.95%	n/a		
Osisko Gold Royalties Ltd	OR	185.1	18.06	Excl.	Excl.	1.33%	n/a		
Africa Oil Corp	AOI	462.3	3.25	Excl.	Excl.	2.10%	n/a		
TMX Group Ltd	X	278.7	29.9	Excl.	Excl.	2.41%	n/a		
Sandstorm Gold Ltd	SSL	296.2	7.46	Excl.	Excl.	1.07%	n/a		
ERO Copper Corp	ERO	93.2	27.95	Excl.	Excl.	n/a	n/a		
Parex Resources Inc	PXT	105.8	25.57	Excl.	Excl.	5.87%	n/a		
Boralex Inc	BLX	102.8	32.78	Excl.	Excl.	2.01%	n/a		
Jamieson Wellness Inc	JWEL	42.0	25.75	Excl.	Excl.	2.95%	n/a		
Methanex Corp	MX	67.4	57.5	Excl.	Excl.	1.74%	n/a		
Restaurant Brands International Inc	QSR	312.3	93.85	29,308	1.58%	3.16%	7.34%	0.0498%	0.1157%
Constellation Software Inc/Canada	CSU	21.2	2775.46	Excl.	Excl.	0.19%	n/a		
Suncor Energy Inc	SU	1300.4	45.77	59,520	3.20%	4.54%	-9.57%	0.1455%	-0.3063%
Seabridge Gold Inc	SEA	83.5	15.86	Excl.	Excl.	n/a	n/a		
Parkland Corp	PKI	175.8	35.75	Excl.	Excl.	3.80%	n/a		
Canada Goose Holdings Inc	GOOS	51.8	21.28	Excl.	Excl.	n/a	21.94%		
Lundin Mining Corp	LUN	773.1	10.48	8,102	0.44%	3.44%	-7.57%	0.0150%	-0.0330%
Wesdome Gold Mines Ltd	WDO	147.5	8.45	Excl.	Excl.	n/a	n/a		
Boyd Group Services Inc	BYD	21.5	243.69	Excl.	Excl.	0.24%	n/a		
Novagold Resources Inc	NG	334.2	5.59	Excl.	Excl.	n/a	n/a		
GFL Environmental Inc	GFL	357.4	43.79	Excl.	Excl.	0.16%	n/a		
Trisura Group Ltd	TSU	47.6	32.05	Excl.	Excl.	n/a	n/a		
Lightspeed Commerce Inc	LSPD	152.2	22.06	Excl.	Excl.	n/a	n/a		
Kinaxis Inc	KXS	28.4	166.57	Excl.	Excl.	n/a	n/a		
Tamarack Valley Energy Ltd	TVE	561.3	3.65	Excl.	Excl.	4.11%	n/a		
Atco Ltd/Canada	ACO/X	100.9	37.3	Excl.	Excl.	5.10%	n/a		
Dundee Precious Metals Inc	DPM	192.7	8.72	Excl.	Excl.	2.47%	n/a		
Spartan Delta Corp	SDE	173.2	4.22	Excl.	Excl.	n/a	n/a		
TFI International Inc	TFII	85.8	184.12	15,798	0.85%	1.01%	32.26%	0.0086%	0.2741%
Stella-Jones Inc	SJ	57.8	65.59	Excl.	Excl.	1.40%	n/a		
Royal Bank of Canada	RY	1395.3	121.74	169,860	9.13%	4.44%	5.00%	0.4052%	0.4567%
Crombie Real Estate Investment Trust	CRR-U	103.8	13.34	Excl.	Excl.	6.67%	n/a		
Russel Metals Inc	RUS	61.3	40.19	Excl.	Excl.	3.98%	n/a		
Stantec Inc	STN	111.0	90.26	Excl.	Excl.	0.86%	n/a		
Transcontinental Inc	TCL/A	73.0	13.23	Excl.	Excl.	6.80%	n/a		
Home Capital Group Inc	HCG	38.6	44.26	Excl.	Excl.	n/a	n/a		
Fortuna Silver Mines Inc	FVI	290.9	4.2	Excl.	Excl.	n/a	n/a		
Endeavour Silver Corp	EDR	191.5	3.85	Excl.	Excl.	n/a	n/a		
Linamar Corp	LNR	61.5	70.91	Excl.	Excl.	1.24%	n/a		
Killam Apartment Real Estate Investment Trust	KMP-U	114.6	18.11	Excl.	Excl.	3.87%	n/a		
North West Co Inc/The	NWC	47.7	30.5	Excl.	Excl.	4.98%	n/a		
Celestica Inc	CLS	112.5	31.5	Excl.	Excl.	n/a	n/a		
SSR Mining Inc	SSRM	203.9	20.04	4,086	0.22%	1.88%	14.87%	0.0041%	0.0327%
Choice Properties Real Estate Investment Trust	CHP-U	327.5	13.11	Excl.	Excl.	5.72%	n/a		
BlackBerry Ltd	BB	583.7	7.54	Excl.	Excl.	n/a	n/a		
Granite Real Estate Investment Trust	GRT-U	63.7	75.28	Excl.	Excl.	4.25%	n/a		
Toromont Industries Ltd	TIH	82.2	110.84	Excl.	Excl.	1.55%	n/a		
First Majestic Silver Corp	FR	286.9	8.29	Excl.	Excl.	0.33%	n/a		
Advantage Energy Ltd	AAV	167.9	9.63	Excl.	Excl.	n/a	n/a		

Canadian Market DCF Calculation as of August 31, 2023

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast Canadian Government Bond 30 Year	Equity Risk Premium
S&P/TSX COMPOSITE INDEX	**3.74%**	**3.83%**	**4.53%**	**8.36%**	**3.52%**	**4.85%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Colliers International Group Inc	CIGI	45.9	156.11	Excl.	Excl.	0.25%	n/a		
Cogeco Communications Inc	CCA	28.8	66.7	1,920	0.10%	4.65%	1.43%	0.0048%	0.0015%
First Capital Real Estate Investment Trust	FCR-U	212.4	13.74	Excl.	Excl.	6.29%	n/a		
First Quantum Minerals Ltd	FM	693.2	36.3	25,164	1.35%	0.44%	3.05%	0.0060%	0.0413%
Pason Systems Inc	PSI	80.1	13.9	Excl.	Excl.	3.45%	n/a		
Pet Valu Holdings Ltd	PET	71.5	25.05	Excl.	Excl.	1.60%	n/a		
Rogers Communications Inc	RCI/B	417.4	54.97	22,945	1.23%	3.64%	13.94%	0.0449%	0.1720%
Shopify Inc	SHOP	1203.2	89.89	Excl.	Excl.	n/a	n/a		
Mullen Group Ltd	MTL	88.7	14.3	Excl.	Excl.	5.03%	n/a		
Maple Leaf Foods Inc	MFI	122.1	29.09	Excl.	Excl.	2.89%	n/a		
Hudbay Minerals Inc	HBM	346.2	6.72	Excl.	Excl.	0.30%	n/a		
Stelco Holdings Inc	STLC	55.1	38.7	Excl.	Excl.	4.34%	n/a		
Labrador Iron Ore Royalty Corp	LIF	64.0	31.41	Excl.	Excl.	8.28%	n/a		
CCL Industries Inc	CCL/B	165.9	60.39	Excl.	Excl.	1.76%	n/a		
StorageVault Canada Inc	SVI	377.6	4.58	Excl.	Excl.	0.25%	n/a		
Superior Plus Corp	SPB	249.3	10.21	Excl.	Excl.	7.05%	n/a		
Freehold Royalties Ltd	FRU	150.6	14.38	Excl.	Excl.	7.51%	n/a		
Westshore Terminals Investment Corp	WTE	63.3	29.09	Excl.	Excl.	4.81%	n/a		
Northland Power Inc	NPI	253.1	25.55	Excl.	Excl.	4.70%	n/a		
Denison Mines Corp	DML	835.9	1.9	Excl.	Excl.	n/a	n/a		
Canadian Apartment Properties REIT	CAR-U	173.3	48.47	Excl.	Excl.	2.99%	n/a		
Peyto Exploration & Development Corp	PEY	175.4	12.55	Excl.	Excl.	10.52%	n/a		
Algonquin Power & Utilities Corp	AQN	688.8	10.23	7,047	0.38%	5.72%	-5.62%	0.0217%	-0.0213%
Dye & Durham Ltd	DND	55.0	18.04	Excl.	Excl.	0.42%	n/a		
SmartCentres Real Estate Investment Trust	SRU-U	144.0	24.05	Excl.	Excl.	7.69%	n/a		
Pan American Silver Corp	PAAS	364.4	22.34	8,142	0.44%	2.42%	116.16%	0.0106%	0.5086%
AltaGas Ltd	ALA	281.7	26.42	7,443	0.40%	4.24%	3.09%	0.0170%	0.0124%
Altus Group Ltd/Canada	AIF	45.9	52.04	2,388	0.13%	1.15%	11.40%	0.0015%	0.0146%
Headwater Exploration Inc	HWX	236.0	7.17	Excl.	Excl.	5.58%	n/a		
Emera Inc	EMA	273.0	50.65	Excl.	Excl.	5.45%	n/a		
Birchcliff Energy Ltd	BIR	266.3	8.35	2,223	0.12%	9.58%	-13.00%	0.0115%	-0.0155%
Primaris Real Estate Investment Trust	PMZ-U	98.3	13.37	Excl.	Excl.	6.13%	n/a		
Torex Gold Resources Inc	TXG	85.9	15.61	Excl.	Excl.	n/a	n/a		
Waste Connections Inc	WCN	257.6	185.24	47,724	2.57%	0.74%	11.95%	0.0191%	0.3067%
Allied Properties Real Estate Investment Trust	AP-U	127.3	20.77	Excl.	Excl.	8.67%	n/a		
Park Lawn Corp	PLC	34.3	22.34	Excl.	Excl.	2.04%	n/a		
Keyera Corp	KEY	229.2	33.38	7,649	0.41%	5.99%	8.00%	0.0246%	0.0329%
NuVista Energy Ltd	NVA	215.8	12.4	Excl.	Excl.	n/a	n/a		
Barrick Gold Corp	ABX	1755.5	21.9	38,445	2.07%	2.47%	6.80%	0.0511%	0.1406%
BCE Inc	BCE	912.3	57.24	Excl.	Excl.	6.76%	n/a		
Chartwell Retirement Residences	CSH-U	232.0	10.27	Excl.	Excl.	5.96%	n/a		
Premium Brands Holdings Corp	PBH	44.6	103.88	Excl.	Excl.	2.96%	n/a		
Equinox Gold Corp	EQX	312.9	6.81	Excl.	Excl.	n/a	n/a		
TC Energy Corp	TRP	1037.5	48.8	50,629	2.72%	7.62%	5.00%	0.2075%	0.1361%
OceanaGold Corp	OGC	708.3	2.92	Excl.	Excl.	0.93%	n/a		
B2Gold Corp	BTO	1295.8	4.16	5,391	0.29%	5.09%	-51.16%	0.0148%	-0.1483%
Bausch Health Cos Inc	BHC	364.3	11.28	Excl.	Excl.	n/a	-4.29%		
Dollarama Inc	DOL	282.7	87.61	Excl.	Excl.	0.32%	n/a		
Capital Power Corp	CPX	117.0	40.67	Excl.	Excl.	6.05%	n/a		
Eldorado Gold Corp	ELD	204.4	12.91	Excl.	Excl.	n/a	56.54%		
Onex Corp	ONEX	79.3	83.49	Excl.	Excl.	0.48%	n/a		
Imperial Oil Ltd	IMO	581.9	76.73	44,647	2.40%	2.61%	-11.03%	0.0626%	-0.2648%
Air Canada	AC	358.5	22.82	Excl.	Excl.	n/a	n/a		
ATS Corp	ATS	98.9	60.62	Excl.	Excl.	n/a	n/a		
Brookfield Renewable Partners LP	BEP-U	288.8	34.16	Excl.	Excl.	5.35%	n/a		
Exchange Income Corp	EIF	46.4	48.39	Excl.	Excl.	5.21%	n/a		

Canadian Market DCF Calculation as of August 31, 2023

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast Canadian Government Bond 30 Year	Equity Risk Premium
S&P/TSX COMPOSITE INDEX	**3.74%**	**3.83%**	**4.53%**	**8.36%**	**3.52%**	**4.85%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Agnico Eagle Mines Ltd	AEM	495.4	65.61	32,506	1.75%	3.29%	-3.48%	0.0575%	-0.0608%
Bombardier Inc	BBD/B	86.9	55.12	Excl.	Excl.	n/a	70.40%		
TELUS Corp	T	1454.4	23.73	34,514	1.86%	6.13%	10.52%	0.1138%	0.1952%
Topaz Energy Corp	TPZ	144.4	21.72	Excl.	Excl.	5.71%	n/a		
Aritzia Inc	ATZ	90.3	24.8	Excl.	Excl.	n/a	7.33%		
InterRent Real Estate Investment Trust	IIP-U	142.1	12.3	Excl.	Excl.	2.93%	n/a		
CAE Inc	CAE	318.1	32.59	Excl.	Excl.	n/a	21.19%		
Canadian Natural Resources Ltd	CNQ	1091.0	87.42	95,371	5.13%	4.12%	-3.47%	0.2112%	-0.1777%
Canadian Tire Corp Ltd	CTC/A	52.4	160.3	Excl.	Excl.	4.30%	n/a		
Algoma Steel Group Inc	ASTL	103.6	10.34	Excl.	Excl.	2.62%	n/a		
Spin Master Corp	TOY	35.1	35.95	Excl.	Excl.	0.67%	n/a		
Canadian Utilities Ltd	CU	201.7	32.02	Excl.	Excl.	5.60%	n/a		
Brookfield Business Partners LP	BBU-U	74.6	20.27	Excl.	Excl.	1.67%	n/a		
CGI Inc	GIB/A	208.9	140.9	Excl.	Excl.	n/a	11.47%		
Fairfax Financial Holdings Ltd	FFH	24.4	1114.27	Excl.	Excl.	1.21%	n/a		
Finning International Inc	FTT	146.0	42.43	Excl.	Excl.	2.36%	n/a		
Badger Infrastructure Solutions Ltd	BDGI	34.5	35.49	Excl.	Excl.	1.94%	n/a		
Fortis Inc/Canada	FTS	486.5	52.99	25,777	1.39%	4.26%	3.81%	0.0591%	0.0528%
Brookfield Asset Management Ltd	BAM	412.6	46.69	Excl.	Excl.	3.71%	n/a		
BRP Inc	DOO	34.9	103.33	Excl.	Excl.	0.70%	n/a		
Great-West Lifeco Inc	GWO	930.8	38.83	Excl.	Excl.	5.36%	n/a		
Enbridge Inc	ENB	2022.7	47.44	95,955	5.16%	7.48%	2.00%	0.3861%	0.1032%
IGM Financial Inc	IGM	238.1	38.52	Excl.	Excl.	5.84%	n/a		
Magna International Inc	MG	286.3	79.48	22,756	1.22%	3.13%	19.26%	0.0383%	0.2357%
Precision Drilling Corp	PD	13.6	89.13	Excl.	Excl.	n/a	n/a		
Paramount Resources Ltd	POU	143.5	31.3	Excl.	Excl.	4.79%	n/a		
SNC-Lavalin Group Inc	ATRL	175.6	44.03	7,730	0.42%	0.18%	36.40%	0.0008%	0.1513%
Boardwalk Real Estate Investment Trust	BEI-U	46.5	68.37	Excl.	Excl.	1.71%	n/a		

Canadian Market DCF Calculation as of August 31, 2023

	[1]	[2]	[3]	[4]			[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return			Forecast Canadian Government Bond 30 Year	Equity Risk Premium
S&P/TSX COMPOSITE INDEX	**3.74%**	**3.83%**	**4.53%**	**8.36%**			**3.52%**	**4.85%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Teck Resources Ltd	TECK/B	512.0	55.88	Excl.	Excl.	0.89%	n/a		
Thomson Reuters Corp	TRI	455.3	173.99	79,218	4.26%	1.52%	15.55%	0.0649%	0.6624%
Whitecap Resources Inc	WCP	605.9	11.05	Excl.	Excl.	5.25%	n/a		
Kinross Gold Corp	K	1227.6	6.86	Excl.	Excl.	2.37%	n/a		
RioCan Real Estate Investment Trust	REI-U	300.4	19.31	Excl.	Excl.	5.59%	n/a		
MAG Silver Corp	MAG	102.9	15.38	Excl.	Excl.	n/a	n/a		
TransAlta Corp	TA	263.4	12.97	Excl.	Excl.	1.70%	n/a		
Cargojet Inc	CJT	17.2	96.09	Excl.	Excl.	1.19%	n/a		
International Petroleum Corp	IPCO	130.2	12.67	Excl.	Excl.	n/a	n/a		
Gibson Energy Inc	GEI	161.7	20.32	3,285	0.18%	7.68%	9.00%	0.0136%	0.0159%
CT Real Estate Investment Trust	CRT-U	107.7	14.56	Excl.	Excl.	6.17%	n/a		
Vermilion Energy Inc	VET	164.0	19.68	Excl.	Excl.	2.03%	n/a		
CI Financial Corp	CIX	169.4	17.34	Excl.	Excl.	4.61%	n/a		
Osisko Mining Inc	OSK	377.1	2.82	Excl.	Excl.	n/a	n/a		
Dream Industrial Real Estate Investment Trust	DIR-U	267.6	13.79	Excl.	Excl.	5.08%	n/a		
Wheaton Precious Metals Corp	WPM	453.0	58.94	26,698	1.44%	1.38%	5.00%	0.0198%	0.0718%
SilverCrest Metals Inc	SIL	147.2	6.69	Excl.	Excl.	n/a	n/a		
WSP Global Inc	WSP	124.6	189.26	Excl.	Excl.	0.79%	n/a		
Alimentation Couche-Tard Inc	ATD	976.9	70.66	69,028	3.71%	0.79%	6.10%	0.0294%	0.2264%
Quebecor Inc	QBR/B	154.0	30.89	4,756	0.26%	3.88%	14.38%	0.0099%	0.0368%
Power Corp of Canada	POW	606.0	36.9	Excl.	Excl.	5.69%	n/a		
Alamos Gold Inc	AGI	396.1	17.38	6,884	0.37%	0.78%	20.11%	0.0029%	0.0744%
Open Text Corp	OTEX	271.2	54.45	Excl.	Excl.	2.49%	n/a		
Definity Financial Corp	DFY	115.9	37.18	Excl.	Excl.	1.48%	n/a		
MTY Food Group Inc	MTY	24.4	66.11	Excl.	Excl.	1.51%	n/a		
goeasy Ltd	GSY	16.5	126.26	Excl.	Excl.	3.04%	n/a		
Canadian National Railway Co	CNR	656.5	152.2	99,912	5.37%	2.08%	5.27%	0.1115%	0.2831%
IAMGOLD Corp	IMG	481.1	3.35	Excl.	Excl.	n/a	37.97%		
K92 Mining Inc	KNT	234.3	6.39	Excl.	Excl.	n/a	n/a		
ARC Resources Ltd	ARX	608.5	20.61	Excl.	Excl.	3.30%	n/a		
Enerplus Corp	ERF	210.7	23.11	Excl.	Excl.	1.41%	n/a		
Average for Companies Paying Dividends with Long-Term Growth Estimates					**100.00%**			**3.74%**	**4.53%**

Notes:
[1] Equals sum of Column [11]
[2] Equals [1] x (1 + 0.5 x [3])
[3] Equals sum of Column [12]
[4] Equals [2] + [3]
[5] Source: Bloomberg Finance L.P., as of August 31, 2023
[6] Source: Bloomberg Finance L.P., as of August 31, 2023
[7] Equals Column [5] x Column [6]. Excludes non-dividend paying companies and companies with no long-term growth estimates.
[8] Equals weight in index based on market capitalization. Excludes non-dividend paying companies and companies with no long-term growth estimates.
[9] Source: Bloomberg Finance L.P., as of August 31, 2023
[10] Source: Bloomberg Finance L.P., as of August 31, 2023
[11] Equals Column [8] x Column [9]
[12] Equals Column [8] x Column [10]
[13] Source: Equals average long-term Consensus Forecast of 10-year government bond yields for the period 2024-2026 as of April 11, 2023 (pp. 3, 28), plus the average spread between 10- and 30-year bond for the past 10 years.
[14] Equals Column [4] - Column [13]

U.S. Market DCF Calculation as of August 31, 2023

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500 INDEX	**1.93%**	**2.04%**	**12.26%**	**14.31%**	**3.98%**	**10.33%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
LyondellBasell Industries NV	LYB	324.2	98.77	32,021	0.11%	5.06%	10.50%	0.0057%	0.0117%
American Express Co	AXP	736.5	157.99	116,353	0.41%	1.52%	11.89%	0.0062%	0.0484%
Verizon Communications Inc	VZ	4204.0	34.98	Excl.	Excl.	7.46%	n/a		
Broadcom Inc	AVGO	412.7	922.89	380,863	1.33%	1.99%	12.40%	0.0265%	0.1650%
Boeing Co/The	BA	603.2	224.03	Excl.	Excl.	n/a	n/a		
Caterpillar Inc	CAT	510.1	281.13	143,417	0.50%	1.85%	15.00%	0.0093%	0.0752%
JPMorgan Chase & Co	JPM	2906.1	146.33	425,247	1.49%	2.73%	-0.50%	0.0406%	-0.0074%
Chevron Corp	CVX	1867.2	161.10	300,813	1.05%	3.75%	14.77%	0.0394%	0.1552%
Coca-Cola Co/The	KO	4324.3	59.83	258,726	0.90%	3.08%	7.19%	0.0278%	0.0650%
AbbVie Inc	ABBV	1765.0	146.96	259,391	0.91%	4.03%	6.50%	0.0365%	0.0589%
Walt Disney Co/The	DIS	1829.8	83.68	Excl.	Excl.	n/a	22.27%		
FleetCor Technologies Inc	FLT	74.0	271.73	Excl.	Excl.	n/a	12.30%		
Extra Space Storage Inc	EXR	211.3	128.68	27,187	0.10%	1.90%	2.46%	0.0018%	0.0023%
Exxon Mobil Corp	XOM	4003.2	111.19	445,115	1.56%	3.27%	13.89%	0.0509%	0.2160%
Phillips 66	PSX	445.3	114.16	50,834	0.18%	3.68%	13.29%	0.0065%	0.0236%
General Electric Co	GE	1088.4	114.46	124,576	0.44%	0.28%	7.00%	0.0012%	0.0305%
HP Inc	HPQ	986.0	29.71	29,293	0.10%	3.53%	-5.48%	0.0036%	-0.0056%
Home Depot Inc/The	HD	1000.1	330.30	330,322	1.15%	2.53%	3.44%	0.0292%	0.0397%
Monolithic Power Systems Inc	MPWR	47.8	521.21	Excl.	Excl.	0.77%	n/a		
International Business Machines Corp	IBM	911.0	146.83	133,763	0.47%	4.52%	3.35%	0.0211%	0.0157%
Johnson & Johnson	JNJ	2401.5	161.68	388,272	1.36%	2.94%	4.00%	0.0399%	0.0543%
McDonald's Corp	MCD	728.8	281.15	204,892	0.72%	2.16%	10.40%	0.0155%	0.0745%
Merck & Co Inc	MRK	2537.5	108.98	276,539	0.97%	2.68%	49.31%	0.0259%	0.4765%
3M Co	MMM	552.0	106.67	58,881	0.21%	5.62%	10.00%	0.0116%	0.0206%
American Water Works Co Inc	AWK	194.7	138.74	27,008	0.09%	2.04%	8.00%	0.0019%	0.0076%
Bank of America Corp	BAC	7946.4	28.67	227,822	0.80%	3.35%	-5.00%	0.0267%	-0.0398%
Pfizer Inc	PFE	5646.0	35.38	199,754	0.70%	4.64%	-3.70%	0.0324%	-0.0258%
Procter & Gamble Co/The	PG	2356.9	154.34	363,763	1.27%	2.44%	6.38%	0.0310%	0.0811%
AT&T Inc	T	7149.0	14.79	105,734	0.37%	7.51%	2.44%	0.0277%	0.0090%
Travelers Cos Inc/The	TRV	228.9	161.23	36,912	0.13%	2.48%	14.92%	0.0032%	0.0192%
RTX Corp	RTX	1455.5	86.04	125,233	0.44%	2.74%	8.88%	0.0120%	0.0388%
Analog Devices Inc	ADI	498.3	181.78	90,584	0.32%	1.89%	6.50%	0.0060%	0.0206%
Walmart Inc	WMT	2692.8	162.61	437,882	1.53%	1.40%	8.00%	0.0215%	0.1224%
Cisco Systems Inc	CSCO	4075.1	57.35	233,705	0.82%	2.72%	7.50%	0.0222%	0.0612%
Intel Corp	INTC	4188.0	35.14	147,166	0.51%	1.42%	5.65%	0.0073%	0.0291%
General Motors Co	GM	1375.9	33.51	46,107	0.16%	1.07%	0.36%	0.0017%	0.0006%
Microsoft Corp	MSFT	7429.8	327.76	2,435,179	8.51%	0.83%	16.62%	0.0706%	1.4143%
Dollar General Corp	DG	219.5	138.50	30,397	0.11%	1.70%	-0.10%	0.0018%	-0.0001%
Cigna Group/The	CI	296.0	276.26	81,767	0.29%	1.78%	9.80%	0.0051%	0.0280%
Kinder Morgan Inc	KMI	2228.2	17.22	38,369	0.13%	6.56%	2.00%	0.0088%	0.0027%
Citigroup Inc	C	1925.7	41.29	79,512	0.28%	5.13%	-8.06%	0.0143%	-0.0224%
American International Group Inc	AIG	711.9	58.52	41,660	0.15%	2.46%	10.00%	0.0036%	0.0146%
Altria Group Inc	MO	1774.6	44.22	78,473	0.27%	8.86%	6.00%	0.0243%	0.0165%
HCA Healthcare Inc	HCA	272.0	277.30	75,422	0.26%	0.87%	7.58%	0.0023%	0.0200%
International Paper Co	IP	346.0	34.92	12,082	0.04%	5.30%	-2.00%	0.0022%	-0.0008%
Hewlett Packard Enterprise Co	HPE	1283.0	16.99	21,798	0.08%	2.83%	3.34%	0.0022%	0.0025%
Abbott Laboratories	ABT	1735.4	102.90	178,568	0.62%	1.98%	2.18%	0.0124%	0.0136%
Aflac Inc	AFL	594.1	74.57	44,299	0.15%	2.25%	5.98%	0.0035%	0.0093%
Air Products and Chemicals Inc	APD	222.1	295.49	65,643	0.23%	2.37%	10.27%	0.0054%	0.0235%
Royal Caribbean Cruises Ltd	RCL	256.2	98.94	Excl.	Excl.	n/a	124.32%		
Hess Corp	HES	307.1	154.50	47,441	0.17%	1.13%	-23.46%	0.0019%	-0.0389%

U.S. Market DCF Calculation as of August 31, 2023

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500 INDEX	**1.93%**	**2.04%**	**12.26%**	**14.31%**	**3.98%**	**10.33%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Archer-Daniels-Midland Co	ADM	536.1	79.30	42,513	0.15%	2.27%	-6.10%	0.0034%	-0.0091%
Automatic Data Processing Inc	ADP	412.0	254.61	104,896	0.37%	1.96%	16.00%	0.0072%	0.0586%
Verisk Analytics Inc	VRSK	145.0	242.22	35,128	0.12%	0.56%	11.58%	0.0007%	0.0142%
AutoZone Inc	AZO	18.2	2531.33	Excl.	Excl.	n/a	13.48%		
Avery Dennison Corp	AVY	80.6	188.38	15,180	0.05%	1.72%	7.00%	0.0009%	0.0037%
Enphase Energy Inc	ENPH	136.4	126.53	Excl.	Excl.	n/a	23.17%		
MSCI Inc	MSCI	79.1	543.62	42,994	0.15%	1.02%	15.26%	0.0015%	0.0229%
Ball Corp	BALL	315.1	54.45	17,155	0.06%	1.47%	10.30%	0.0009%	0.0062%
Axon Enterprise Inc	AXON	74.8	212.91	Excl.	Excl.	n/a	n/a		
Ceridian HCM Holding Inc	CDAY	155.6	72.52	Excl.	Excl.	n/a	n/a		
Carrier Global Corp	CARR	837.6	57.45	48,122	0.17%	1.29%	10.65%	0.0022%	0.0179%
Bank of New York Mellon Corp/The	BK	778.8	44.87	34,944	0.12%	3.74%	10.00%	0.0046%	0.0122%
Otis Worldwide Corp	OTIS	411.7	85.55	Excl.	Excl.	1.59%	n/a		
Baxter International Inc	BAX	506.4	40.60	20,560	0.07%	2.86%	0.66%	0.0021%	0.0005%
Becton Dickinson & Co	BDX	290.1	279.45	81,071	0.28%	1.30%	9.36%	0.0037%	0.0265%
Berkshire Hathaway Inc	BRK/B	1308.1	360.20	Excl.	Excl.	n/a	n/a		
Best Buy Co Inc	BBY	218.2	76.45	16,682	0.06%	4.81%	3.21%	0.0028%	0.0019%
Boston Scientific Corp	BSX	1464.2	53.94	Excl.	Excl.	n/a	12.10%		
Bristol-Myers Squibb Co	BMY	2089.1	61.65	128,793	0.45%	3.70%	3.10%	0.0166%	0.0140%
Brown-Forman Corp	BF/B	310.1	66.13	20,509	0.07%	1.24%	7.04%	0.0009%	0.0050%
Coterra Energy Inc	CTRA	755.0	28.19	21,285	0.07%	2.84%	23.02%	0.0021%	0.0171%
Campbell Soup Co	CPB	298.1	41.70	12,430	0.04%	3.55%	3.06%	0.0015%	0.0013%
Hilton Worldwide Holdings Inc	HLT	261.5	148.65	38,874	0.14%	0.40%	17.14%	0.0005%	0.0233%
Carnival Corp	CCL	1116.0	15.82	Excl.	Excl.	n/a	n/a		
Qorvo Inc	QRVO	97.9	107.39	Excl.	Excl.	n/a	2.83%		
UDR Inc	UDR	329.5	39.90	13,146	0.05%	4.21%	7.46%	0.0019%	0.0034%
Clorox Co/The	CLX	123.8	156.45	19,373	0.07%	3.07%	17.90%	0.0021%	0.0121%
Paycom Software Inc	PAYC	60.5	294.84	Excl.	Excl.	0.51%	n/a		
CMS Energy Corp	CMS	291.7	56.19	Excl.	Excl.	3.47%	n/a		
Newell Brands Inc	NWL	414.2	10.58	Excl.	Excl.	2.65%	n/a		
Colgate-Palmolive Co	CL	826.7	73.47	60,737	0.21%	2.61%	7.85%	0.0055%	0.0167%
EPAM Systems Inc	EPAM	58.0	258.99	Excl.	Excl.	n/a	4.70%		
Comerica Inc	CMA	131.8	48.11	6,340	0.02%	5.90%	-6.12%	0.0013%	-0.0014%
Conagra Brands Inc	CAG	477.9	29.88	14,279	0.05%	4.69%	1.31%	0.0023%	0.0007%
Consolidated Edison Inc	ED	344.9	88.96	30,684	0.11%	3.64%	4.00%	0.0039%	0.0043%
Corning Inc	GLW	853.0	32.82	27,995	0.10%	3.41%	6.58%	0.0033%	0.0064%
Cummins Inc	CMI	141.6	230.04	Excl.	Excl.	2.92%	n/a		
Caesars Entertainment Inc	CZR	215.3	55.26	Excl.	Excl.	n/a	n/a		
Danaher Corp	DHR	738.4	265.00	195,663	0.68%	0.41%	1.00%	0.0028%	0.0068%
Target Corp	TGT	461.6	126.55	58,416	0.20%	3.48%	2.51%	0.0071%	0.0051%
Deere & Co	DE	288.0	410.94	118,351	0.41%	1.31%	18.05%	0.0054%	0.0746%
Dominion Energy Inc	D	836.8	48.54	40,617	0.14%	5.50%	0.30%	0.0078%	0.0004%
Dover Corp	DOV	139.9	148.30	20,743	0.07%	1.38%	13.00%	0.0010%	0.0094%
Alliant Energy Corp	LNT	252.7	50.17	12,679	0.04%	3.61%	6.48%	0.0016%	0.0029%
Steel Dynamics Inc	STLD	165.6	106.59	17,656	0.06%	1.59%	-16.45%	0.0010%	-0.0101%
Duke Energy Corp	DUK	771.0	88.80	68,465	0.24%	4.62%	6.10%	0.0110%	0.0146%
Regency Centers Corp	REG	171.0	62.20	10,636	0.04%	4.18%	5.02%	0.0016%	0.0019%
Eaton Corp PLC	ETN	399.0	230.37	91,918	0.32%	1.49%	15.00%	0.0048%	0.0482%
Ecolab Inc	ECL	285.0	183.81	52,392	0.18%	1.15%	16.00%	0.0021%	0.0293%
Revvity Inc	RVTY	124.1	117.03	14,528	0.05%	0.24%	46.45%	0.0001%	0.0236%
Emerson Electric Co	EMR	571.5	98.25	56,150	0.20%	2.12%	11.80%	0.0042%	0.0232%

U.S. Market DCF Calculation as of August 31, 2023

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S&P 500 INDEX	**1.93%**	**2.04%**	**12.26%**	**14.31%**	**3.98%**	**10.33%**

Company	Ticker	[5] Shares Outstanding (million)	[6] Price ($)	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
EOG Resources Inc	EOG	582.3	128.62	74,890	0.26%	2.57%	11.33%	0.0067%	0.0296%
Aon PLC	AON	202.9	333.39	67,634	0.24%	0.74%	9.17%	0.0017%	0.0217%
Entergy Corp	ETR	211.5	95.25	20,141	0.07%	4.49%	6.33%	0.0032%	0.0045%
Equifax Inc	EFX	122.7	206.70	25,366	0.09%	0.75%	11.40%	0.0007%	0.0101%
EQT Corp	EQT	411.3	43.22	17,775	0.06%	1.39%	22.19%	0.0009%	0.0138%
IQVIA Holdings Inc	IQV	183.1	222.63	Excl.	Excl.	n/a	13.16%		
Gartner Inc	IT	78.8	349.68	Excl.	Excl.	n/a	7.22%		
FedEx Corp	FDX	251.5	261.02	65,649	0.23%	1.93%	13.00%	0.0044%	0.0298%
FMC Corp	FMC	124.7	86.23	10,756	0.04%	2.69%	8.00%	0.0010%	0.0030%
Brown & Brown Inc	BRO	283.6	74.10	21,016	0.07%	0.62%	9.00%	0.0005%	0.0066%
Ford Motor Co	F	3931.4	12.13	47,688	0.17%	4.95%	10.96%	0.0082%	0.0183%
NextEra Energy Inc	NEE	2023.7	66.80	135,184	0.47%	2.80%	8.75%	0.0132%	0.0413%
Franklin Resources Inc	BEN	499.0	26.74	13,343	0.05%	4.49%	-6.13%	0.0021%	-0.0029%
Garmin Ltd	GRMN	191.5	106.02	20,298	0.07%	2.75%	5.60%	0.0020%	0.0040%
Freeport-McMoRan Inc	FCX	1433.6	39.91	Excl.	Excl.	1.50%	n/a		
Dexcom Inc	DXCM	387.9	100.98	Excl.	Excl.	n/a	30.96%		
General Dynamics Corp	GD	273.0	226.64	61,882	0.22%	2.33%	10.90%	0.0050%	0.0236%
General Mills Inc	GIS	581.2	67.66	39,323	0.14%	3.49%	8.00%	0.0048%	0.0110%
Genuine Parts Co	GPC	140.4	153.73	21,590	0.08%	2.47%	8.95%	0.0019%	0.0068%
Atmos Energy Corp	ATO	148.5	115.95	17,214	0.06%	2.55%	7.50%	0.0015%	0.0045%
WW Grainger Inc	GWW	50.0	714.14	Excl.	Excl.	1.04%	n/a		
Halliburton Co	HAL	898.5	38.62	34,702	0.12%	1.66%	23.40%	0.0020%	0.0284%
L3Harris Technologies Inc	LHX	189.1	178.09	33,683	0.12%	2.56%	2.50%	0.0030%	0.0029%
Healthpeak Properties Inc	PEAK	547.1	20.58	11,258	0.04%	5.83%	4.72%	0.0023%	0.0019%
Insulet Corp	PODD	69.8	191.71	Excl.	Excl.	n/a	36.33%		
Catalent Inc	CTLT	180.3	49.97	Excl.	Excl.	n/a	12.00%		
Fortive Corp	FTV	352.0	78.85	27,757	0.10%	0.36%	7.93%	0.0003%	0.0077%
Hershey Co/The	HSY	149.9	214.86	32,198	0.11%	2.22%	9.50%	0.0025%	0.0107%
Synchrony Financial	SYF	418.2	32.28	13,499	0.05%	3.10%	64.00%	0.0015%	0.0302%
Hormel Foods Corp	HRL	546.5	38.59	21,089	0.07%	2.85%	2.50%	0.0021%	0.0018%
Arthur J Gallagher & Co	AJG	215.5	230.48	49,670	0.17%	0.95%	12.19%	0.0017%	0.0212%
Mondelez International Inc	MDLZ	1360.4	71.26	96,943	0.34%	2.39%	8.04%	0.0081%	0.0272%
CenterPoint Energy Inc	CNP	629.4	27.89	Excl.	Excl.	2.72%	n/a		
Humana Inc	HUM	123.9	461.63	57,199	0.20%	0.77%	12.32%	0.0015%	0.0246%
Willis Towers Watson PLC	WTW	104.8	206.76	21,673	0.08%	1.63%	10.82%	0.0012%	0.0082%
Illinois Tool Works Inc	ITW	302.4	247.35	74,796	0.26%	2.26%	3.94%	0.0059%	0.0103%
CDW Corp/DE	CDW	134.0	211.15	28,304	0.10%	1.12%	13.10%	0.0011%	0.0130%
Trane Technologies PLC	TT	228.4	205.26	46,881	0.16%	1.46%	11.68%	0.0024%	0.0191%
Interpublic Group of Cos Inc/The	IPG	384.9	32.61	12,553	0.04%	3.80%	6.99%	0.0017%	0.0031%
International Flavors & Fragrances Inc	IFF	255.3	70.45	17,983	0.06%	4.60%	-1.16%	0.0029%	-0.0007%
Generac Holdings Inc	GNRC	62.2	118.81	Excl.	Excl.	n/a	4.50%		
NXP Semiconductors NV	NXPI	257.8	205.72	53,035	0.19%	1.97%	20.50%	0.0037%	0.0380%
Kellogg Co	K	342.3	61.02	20,890	0.07%	3.93%	4.51%	0.0029%	0.0033%
Broadridge Financial Solutions Inc	BR	118.1	186.21	Excl.	Excl.	1.72%	n/a		
Kimberly-Clark Corp	KMB	338.2	128.83	43,568	0.15%	3.66%	9.71%	0.0056%	0.0148%
Kimco Realty Corp	KIM	619.9	18.94	11,741	0.04%	4.86%	4.65%	0.0020%	0.0019%
Oracle Corp	ORCL	2714.3	120.39	326,770	1.14%	1.33%	15.00%	0.0152%	0.1713%
Kroger Co/The	KR	717.7	46.39	33,296	0.12%	2.50%	4.76%	0.0029%	0.0055%
Lennar Corp	LEN	252.5	119.09	30,073	0.11%	1.26%	-3.15%	0.0013%	-0.0033%
Eli Lilly & Co	LLY	949.3	554.20	526,099	1.84%	0.82%	23.35%	0.0150%	0.4293%
Bath & Body Works Inc	BBWI	228.9	36.87	8,440	0.03%	2.17%	11.38%	0.0006%	0.0034%

U.S. Market DCF Calculation as of August 31, 2023

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S&P 500 INDEX	**1.93%**	**2.04%**	**12.26%**	**14.31%**	**3.98%**	**10.33%**

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Charter Communications Inc	CHTR	149.7	438.12	Excl.	Excl.	n/a	15.90%		
Lincoln National Corp	LNC	169.6	25.66	Excl.	Excl.	7.01%	n/a		
Loews Corp	L	225.5	62.09	Excl.	Excl.	0.40%	n/a		
Lowe's Cos Inc	LOW	577.1	230.48	133,013	0.46%	1.91%	20.64%	0.0089%	0.0959%
IDEX Corp	IEX	75.6	226.40	17,116	0.06%	1.13%	10.00%	0.0007%	0.0060%
Marsh & McLennan Cos Inc	MMC	494.0	194.99	96,316	0.34%	1.46%	11.25%	0.0049%	0.0378%
Masco Corp	MAS	224.9	59.01	13,273	0.05%	1.93%	6.74%	0.0009%	0.0031%
S&P Global Inc	SPGI	318.2	390.86	124,372	0.43%	0.92%	13.72%	0.0040%	0.0596%
Medtronic PLC	MDT	1330.5	81.50	108,439	0.38%	3.39%	3.17%	0.0128%	0.0120%
Viatris Inc	VTRS	1199.5	10.75	12,895	0.05%	4.47%	-2.18%	0.0020%	-0.0010%
CVS Health Corp	CVS	1284.4	65.17	83,704	0.29%	3.71%	7.13%	0.0109%	0.0209%
DuPont de Nemours Inc	DD	459.1	76.89	35,297	0.12%	1.87%	12.85%	0.0023%	0.0158%
Micron Technology Inc	MU	1095.3	69.94	76,605	0.27%	0.66%	-15.93%	0.0018%	-0.0426%
Motorola Solutions Inc	MSI	167.0	283.57	Excl.	Excl.	1.24%	n/a		
Cboe Global Markets Inc	CBOE	105.5	149.71	Excl.	Excl.	1.47%	n/a		
Laboratory Corp of America Holdings	LH	88.6	208.10	18,438	0.06%	1.38%	-4.73%	0.0009%	-0.0030%
Newmont Corp	NEM	794.7	39.42	31,328	0.11%	4.06%	11.86%	0.0044%	0.0130%
NIKE Inc	NKE	1225.1	101.71	124,602	0.44%	1.34%	15.34%	0.0058%	0.0668%
NiSource Inc	NI	413.3	26.76	11,059	0.04%	3.74%	7.50%	0.0014%	0.0029%
Norfolk Southern Corp	NSC	227.0	205.01	46,540	0.16%	2.63%	4.34%	0.0043%	0.0071%
Principal Financial Group Inc	PFG	241.7	77.71	18,784	0.07%	3.35%	7.38%	0.0022%	0.0048%
Eversource Energy	ES	349.1	63.82	22,279	0.08%	4.23%	4.99%	0.0033%	0.0039%
Northrop Grumman Corp	NOC	151.3	433.09	65,527	0.23%	1.73%	4.06%	0.0040%	0.0093%
Wells Fargo & Co	WFC	3667.7	41.29	151,439	0.53%	3.39%	13.41%	0.0179%	0.0710%
Nucor Corp	NUE	248.7	172.10	42,805	0.15%	1.19%	-10.89%	0.0018%	-0.0163%
Occidental Petroleum Corp	OXY	884.7	62.79	55,549	0.19%	1.15%	-13.74%	0.0022%	-0.0267%
Omnicom Group Inc	OMC	197.6	81.01	16,005	0.06%	3.46%	6.31%	0.0019%	0.0035%
ONEOK Inc	OKE	447.7	65.20	29,188	0.10%	5.86%	7.08%	0.0060%	0.0072%
Raymond James Financial Inc	RJF	208.8	104.59	Excl.	Excl.	1.61%	n/a		
PG&E Corp	PCG	2091.2	16.30	Excl.	Excl.	n/a	8.50%		
Parker-Hannifin Corp	PH	128.4	416.90	53,543	0.19%	1.42%	14.56%	0.0027%	0.0272%
Rollins Inc	ROL	492.8	39.57	19,501	0.07%	1.31%	13.72%	0.0009%	0.0093%
PPL Corp	PPL	737.1	24.92	18,368	0.06%	3.85%	7.21%	0.0025%	0.0046%
ConocoPhillips	COP	1197.5	119.03	142,537	0.50%	0.50%	-0.50%	0.0025%	-0.0025%
PulteGroup Inc	PHM	219.4	82.06	18,008	0.06%	0.78%	-3.91%	0.0005%	-0.0025%
Pinnacle West Capital Corp	PNW	113.3	77.27	8,756	0.03%	4.48%	6.46%	0.0014%	0.0020%
PNC Financial Services Group Inc/The	PNC	398.3	120.73	48,081	0.17%	5.14%	-0.12%	0.0086%	-0.0002%
PPG Industries Inc	PPG	235.5	141.76	33,386	0.12%	1.83%	11.30%	0.0021%	0.0132%
Progressive Corp/The	PGR	585.1	133.47	78,093	0.27%	0.30%	38.38%	0.0008%	0.1047%
Public Service Enterprise Group Inc	PEG	499.1	61.08	30,486	0.11%	3.73%	6.73%	0.0040%	0.0072%
Robert Half Inc	RHI	107.1	73.96	7,920	0.03%	2.60%	0.78%	0.0007%	0.0002%
Edison International	EIX	383.3	68.85	26,389	0.09%	4.28%	5.35%	0.0040%	0.0049%
Schlumberger NV	SLB	1421.2	58.96	83,793	0.29%	1.70%	27.56%	0.0050%	0.0807%
Charles Schwab Corp/The	SCHW	1770.2	59.15	104,709	0.37%	1.69%	5.31%	0.0062%	0.0194%
Sherwin-Williams Co/The	SHW	257.1	271.72	69,873	0.24%	0.89%	8.49%	0.0022%	0.0207%
West Pharmaceutical Services Inc	WST	73.9	406.90	30,054	0.11%	0.19%	18.65%	0.0002%	0.0196%
J M Smucker Co/The	SJM	102.1	144.95	14,804	0.05%	2.93%	6.09%	0.0015%	0.0032%
Snap-on Inc	SNA	52.9	268.60	14,214	0.05%	2.41%	4.87%	0.0012%	0.0024%
AMETEK Inc	AME	230.7	159.51	36,801	0.13%	0.63%	9.74%	0.0008%	0.0125%
Southern Co/The	SO	1091.5	67.73	73,928	0.26%	4.13%	4.50%	0.0107%	0.0116%
Truist Financial Corp	TFC	1332.0	30.55	40,692	0.14%	6.81%	4.13%	0.0097%	0.0059%

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Southwest Airlines Co	LUV	595.6	31.60	18,822	0.07%	2.28%	29.08%	0.0015%	0.0191%
W R Berkley Corp	WRB	257.5	61.86	15,930	0.06%	0.71%	12.50%	0.0004%	0.0070%
Stanley Black & Decker Inc	SWK	153.2	94.38	Excl.	Excl.	3.43%	n/a		
Public Storage	PSA	175.8	276.38	48,596	0.17%	4.34%	3.73%	0.0074%	0.0063%
Arista Networks Inc	ANET	309.6	195.23	Excl.	Excl.	n/a	19.35%		
Sysco Corp	SYY	504.9	69.65	Excl.	Excl.	2.87%	n/a		
Corteva Inc	CTVA	709.5	50.51	35,838	0.13%	1.27%	17.92%	0.0016%	0.0224%
Texas Instruments Inc	TXN	908.0	168.06	152,593	0.53%	2.95%	7.80%	0.0157%	0.0416%
Textron Inc	TXT	198.1	77.71	15,392	0.05%	0.10%	11.73%	0.0001%	0.0063%
Thermo Fisher Scientific Inc	TMO	386.0	557.10	Excl.	Excl.	0.25%	n/a		
TJX Cos Inc/The	TJX	1144.1	92.48	105,805	0.37%	1.44%	10.00%	0.0053%	0.0370%
Globe Life Inc	GL	94.8	111.57	Excl.	Excl.	0.81%	n/a		
Johnson Controls International plc	JCI	680.3	59.06	40,180	0.14%	2.51%	15.62%	0.0035%	0.0219%
Ulta Beauty Inc	ULTA	49.2	415.03	Excl.	Excl.	n/a	6.54%		
Union Pacific Corp	UNP	609.5	220.57	134,428	0.47%	2.36%	6.50%	0.0111%	0.0305%
Keysight Technologies Inc	KEYS	177.6	133.30	Excl.	Excl.	n/a	2.52%		
UnitedHealth Group Inc	UNH	926.3	476.58	441,458	1.54%	1.58%	11.90%	0.0243%	0.1835%
Marathon Oil Corp	MRO	605.7	26.35	15,960	0.06%	1.52%	-10.70%	0.0008%	-0.0060%
Bio-Rad Laboratories Inc	BIO	24.0	400.20	Excl.	Excl.	n/a	6.00%		
Ventas Inc	VTR	402.4	43.68	17,576	0.06%	4.12%	8.12%	0.0025%	0.0050%
VF Corp	VFC	388.9	19.76	7,684	0.03%	6.07%	11.54%	0.0016%	0.0031%
Vulcan Materials Co	VMC	132.9	218.25	28,998	0.10%	0.79%	21.48%	0.0008%	0.0218%
Weyerhaeuser Co	WY	730.7	32.75	Excl.	Excl.	2.32%	n/a		
Whirlpool Corp	WHR	54.8	139.96	7,672	0.03%	5.00%	-1.35%	0.0013%	-0.0004%
Williams Cos Inc/The	WMB	1216.4	34.53	42,003	0.15%	5.18%	3.50%	0.0076%	0.0051%
Constellation Energy Corp	CEG	321.6	104.16	33,497	0.12%	1.08%	23.30%	0.0013%	0.0273%
WEC Energy Group Inc	WEC	315.4	84.12	26,534	0.09%	3.71%	6.26%	0.0034%	0.0058%
Adobe Inc	ADBE	455.8	559.34	Excl.	Excl.	n/a	16.90%		
AES Corp/The	AES	669.6	17.93	12,006	0.04%	3.70%	9.12%	0.0016%	0.0038%
Amgen Inc	AMGN	534.9	256.34	137,117	0.48%	3.32%	4.00%	0.0159%	0.0192%
Apple Inc	AAPL	15634.2	187.87	2,937,203	10.26%	0.51%	11.00%	0.0524%	1.1290%
Autodesk Inc	ADSK	213.8	221.94	Excl.	Excl.	n/a	13.86%		
Cintas Corp	CTAS	101.7	504.17	51,295	0.18%	1.07%	9.74%	0.0019%	0.0175%
Comcast Corp	CMCSA	4115.7	46.76	192,450	0.67%	2.48%	8.68%	0.0167%	0.0584%
Molson Coors Beverage Co	TAP	201.0	63.49	12,759	0.04%	2.58%	7.07%	0.0012%	0.0032%
KLA Corp	KLAC	136.7	501.87	68,616	0.24%	1.04%	9.27%	0.0025%	0.0222%
Marriott International Inc/MD	MAR	298.2	203.51	60,695	0.21%	1.02%	17.05%	0.0022%	0.0362%
Fiserv Inc	FI	609.6	121.39	Excl.	Excl.	n/a	14.63%		
McCormick & Co Inc/MD	MKC	251.1	82.08	20,610	0.07%	1.90%	7.01%	0.0014%	0.0050%
PACCAR Inc	PCAR	522.8	82.29	43,022	0.15%	1.31%	12.00%	0.0020%	0.0180%
Costco Wholesale Corp	COST	443.1	549.28	243,412	0.85%	0.74%	12.46%	0.0063%	0.1060%
Stryker Corp	SYK	379.8	283.55	107,686	0.38%	1.06%	7.07%	0.0040%	0.0266%
Tyson Foods Inc	TSN	285.6	53.27	15,211	0.05%	3.60%	-22.91%	0.0019%	-0.0122%
Lamb Weston Holdings Inc	LW	145.7	97.41	14,189	0.05%	1.15%	12.14%	0.0006%	0.0060%
Applied Materials Inc	AMAT	836.5	152.76	127,789	0.45%	0.84%	3.73%	0.0037%	0.0167%
American Airlines Group Inc	AAL	653.4	14.73	Excl.	Excl.	n/a	80.75%		
Cardinal Health Inc	CAH	250.7	87.33	Excl.	Excl.	2.29%	n/a		
Cincinnati Financial Corp	CINF	156.9	105.79	16,594	0.06%	2.84%	17.66%	0.0016%	0.0102%
Paramount Global	PARA	610.4	15.09	9,211	0.03%	1.33%	5.71%	0.0004%	0.0018%
DR Horton Inc	DHI	338.3	119.02	40,264	0.14%	0.84%	-8.43%	0.0012%	-0.0119%
Electronic Arts Inc	EA	270.9	119.98	32,504	0.11%	0.63%	5.64%	0.0007%	0.0064%

U.S. Market DCF Calculation as of August 31, 2023

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500 INDEX	**1.93%**	**2.04%**	**12.26%**	**14.31%**	**3.98%**	**10.33%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Fair Isaac Corp	FICO	24.9	904.59	Excl.	Excl.	n/a	n/a		
Expeditors International of Washington Inc	EXPD	147.9	116.71	Excl.	Excl.	1.18%	n/a		
Fastenal Co	FAST	571.3	57.58	Excl.	Excl.	2.43%	n/a		
M&T Bank Corp	MTB	165.9	125.05	20,752	0.07%	4.16%	11.10%	0.0030%	0.0080%
Xcel Energy Inc	XEL	551.5	57.13	31,509	0.11%	3.64%	6.14%	0.0040%	0.0068%
Fifth Third Bancorp	FITB	680.9	26.55	18,078	0.06%	4.97%	25.00%	0.0031%	0.0158%
Gilead Sciences Inc	GILD	1246.0	76.48	95,295	0.33%	3.92%	0.73%	0.0131%	0.0024%
Hasbro Inc	HAS	138.7	72.00	9,989	0.03%	3.89%	8.64%	0.0014%	0.0030%
Huntington Bancshares Inc/OH	HBAN	1447.9	11.09	16,057	0.06%	5.59%	-5.65%	0.0031%	-0.0032%
Welltower Inc	WELL	518.7	82.88	42,992	0.15%	2.94%	10.72%	0.0044%	0.0161%
Biogen Inc	BIIB	144.8	267.36	Excl.	Excl.	n/a	0.06%		
Northern Trust Corp	NTRS	207.0	76.07	15,747	0.06%	3.94%	13.00%	0.0022%	0.0072%
Packaging Corp of America	PKG	89.9	149.10	13,406	0.05%	3.35%	3.00%	0.0016%	0.0014%
Paychex Inc	PAYX	360.5	122.23	44,070	0.15%	2.91%	7.00%	0.0045%	0.0108%
QUALCOMM Inc	QCOM	1116.0	114.53	Excl.	Excl.	2.79%	n/a		
Ross Stores Inc	ROST	340.7	121.81	41,495	0.14%	1.10%	10.00%	0.0016%	0.0145%
IDEXX Laboratories Inc	IDXX	83.0	511.41	Excl.	Excl.	n/a	17.57%		
Starbucks Corp	SBUX	1145.4	97.44	111,608	0.39%	2.18%	19.71%	0.0085%	0.0768%
KeyCorp	KEY	935.9	11.33	10,604	0.04%	7.24%	7.53%	0.0027%	0.0028%
Fox Corp	FOXA	253.7	33.06	8,387	0.03%	1.57%	12.00%	0.0005%	0.0035%
Fox Corp	FOX	235.6	30.52	7,190	0.03%	1.70%	12.00%	0.0004%	0.0030%
State Street Corp	STT	318.6	68.74	21,903	0.08%	4.02%	1.31%	0.0031%	0.0010%
Norwegian Cruise Line Holdings Ltd	NCLH	425.4	16.57	Excl.	Excl.	n/a	n/a		
US Bancorp	USB	1557.0	36.53	56,876	0.20%	5.26%	8.00%	0.0104%	0.0159%
A O Smith Corp	AOS	124.6	72.50	Excl.	Excl.	1.66%	n/a		
Gen Digital Inc	GEN	639.4	20.25	Excl.	Excl.	2.47%	n/a		
T Rowe Price Group Inc	TROW	224.3	112.23	25,173	0.09%	4.35%	-3.36%	0.0038%	-0.0030%
Waste Management Inc	WM	405.1	156.78	63,505	0.22%	1.79%	9.80%	0.0040%	0.0217%
Constellation Brands Inc	STZ	183.3	260.56	47,761	0.17%	1.37%	9.73%	0.0023%	0.0162%
DENTSPLY SIRONA Inc	XRAY	211.7	37.09	7,853	0.03%	1.51%	9.78%	0.0004%	0.0027%
Zions Bancorp NA	ZION	148.1	35.50	5,259	0.02%	4.62%	-3.00%	0.0008%	-0.0006%
Alaska Air Group Inc	ALK	127.2	41.97	Excl.	Excl.	n/a	23.98%		
Invesco Ltd	IVZ	448.6	15.92	7,142	0.02%	5.03%	4.26%	0.0013%	0.0011%
Intuit Inc	INTU	280.1	541.81	151,739	0.53%	0.66%	18.84%	0.0035%	0.0999%
Morgan Stanley	MS	1657.0	85.15	141,091	0.49%	3.99%	3.76%	0.0197%	0.0185%
Microchip Technology Inc	MCHP	544.3	81.84	44,548	0.16%	2.00%	12.06%	0.0031%	0.0188%
Chubb Ltd	CB	410.7	200.87	82,504	0.29%	1.71%	14.50%	0.0049%	0.0418%
Hologic Inc	HOLX	244.9	74.74	Excl.	Excl.	n/a	-14.09%		
Citizens Financial Group Inc	CFG	472.3	28.13	13,286	0.05%	5.97%	-6.14%	0.0028%	-0.0029%
O'Reilly Automotive Inc	ORLY	60.3	939.70	Excl.	Excl.	n/a	12.13%		
Allstate Corp/The	ALL	261.6	107.81	28,200	0.10%	3.30%	-4.00%	0.0033%	-0.0039%
Equity Residential	EQR	379.0	64.83	24,573	0.09%	4.09%	5.68%	0.0035%	0.0049%
BorgWarner Inc	BWA	235.1	40.75	9,579	0.03%	1.08%	5.31%	0.0004%	0.0018%
Keurig Dr Pepper Inc	KDP	1397.3	33.65	47,018	0.16%	2.38%	6.35%	0.0039%	0.0104%
Organon & Co	OGN	255.6	21.96	5,612	0.02%	5.10%	7.34%	0.0010%	0.0014%
Host Hotels & Resorts Inc	HST	711.6	15.79	Excl.	Excl.	3.80%	n/a		
Incyte Corp	INCY	224.1	64.53	Excl.	Excl.	n/a	65.18%		
Simon Property Group Inc	SPG	327.2	113.49	37,133	0.13%	6.70%	2.04%	0.0087%	0.0026%
Eastman Chemical Co	EMN	118.6	85.01	10,078	0.04%	3.72%	5.93%	0.0013%	0.0021%
AvalonBay Communities Inc	AVB	142.0	183.82	26,105	0.09%	3.59%	10.28%	0.0033%	0.0094%
Prudential Financial Inc	PRU	363.0	94.67	34,365	0.12%	5.28%	10.60%	0.0063%	0.0127%

U.S. Market DCF Calculation as of August 31, 2023

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500 INDEX	**1.93%**	**2.04%**	**12.26%**	**14.31%**	**3.98%**	**10.33%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
United Parcel Service Inc	UPS	723.3	169.40	122,523	0.43%	3.83%	-3.89%	0.0164%	-0.0167%
Walgreens Boots Alliance Inc	WBA	863.3	25.31	21,849	0.08%	7.59%	-6.57%	0.0058%	-0.0050%
STERIS PLC	STE	98.8	229.59	Excl.	Excl.	0.91%	n/a		
McKesson Corp	MCK	134.9	412.32	55,623	0.19%	0.60%	10.03%	0.0012%	0.0195%
Lockheed Martin Corp	LMT	251.8	448.35	112,908	0.39%	2.68%	6.98%	0.0106%	0.0275%
Cencora Inc	COR	202.2	175.98	35,579	0.12%	1.10%	9.44%	0.0014%	0.0117%
Capital One Financial Corp	COF	381.4	102.39	39,056	0.14%	2.34%	-2.93%	0.0032%	-0.0040%
Waters Corp	WAT	59.1	280.80	Excl.	Excl.	n/a	5.79%		
Nordson Corp	NDSN	57.0	244.14	Excl.	Excl.	1.11%	n/a		
Dollar Tree Inc	DLTR	220.0	122.36	Excl.	Excl.	n/a	7.37%		
Darden Restaurants Inc	DRI	120.9	155.51	18,797	0.07%	3.37%	10.79%	0.0022%	0.0071%
Evergy Inc	EVRG	229.6	54.97	12,620	0.04%	4.46%	4.74%	0.0020%	0.0021%
Match Group Inc	MTCH	278.1	46.87	Excl.	Excl.	n/a	62.00%		
Domino's Pizza Inc	DPZ	35.1	387.40	13,595	0.05%	1.25%	13.94%	0.0006%	0.0066%
NVR Inc	NVR	3.3	6377.33	Excl.	Excl.	n/a	-3.60%		
NetApp Inc	NTAP	208.8	76.70	16,014	0.06%	2.61%	7.40%	0.0015%	0.0041%
DXC Technology Co	DXC	205.2	20.74	Excl.	Excl.	n/a	6.84%		
Old Dominion Freight Line Inc	ODFL	109.3	427.37	46,698	0.16%	0.37%	4.45%	0.0006%	0.0073%
DaVita Inc	DVA	91.3	102.42	Excl.	Excl.	n/a	15.78%		
Hartford Financial Services Group Inc/The	HIG	305.8	71.82	21,964	0.08%	2.37%	7.00%	0.0018%	0.0054%
Iron Mountain Inc	IRM	291.9	63.54	18,544	0.06%	4.09%	4.00%	0.0027%	0.0026%
Estee Lauder Cos Inc/The	EL	232.1	160.53	37,267	0.13%	1.64%	8.40%	0.0021%	0.0109%
Cadence Design Systems Inc	CDNS	271.8	240.44	Excl.	Excl.	n/a	19.00%		
Tyler Technologies Inc	TYL	42.1	398.43	Excl.	Excl.	n/a	n/a		
Universal Health Services Inc	UHS	62.1	134.70	8,370	0.03%	0.59%	11.82%	0.0002%	0.0035%
Skyworks Solutions Inc	SWKS	159.4	108.74	17,332	0.06%	2.50%	4.99%	0.0015%	0.0030%
Quest Diagnostics Inc	DGX	112.2	131.50	14,759	0.05%	2.16%	-0.67%	0.0011%	-0.0003%
Activision Blizzard Inc	ATVI	786.8	91.99	72,378	0.25%	1.08%	7.00%	0.0027%	0.0177%
Rockwell Automation Inc	ROK	114.9	312.08	35,846	0.13%	1.51%	15.59%	0.0019%	0.0195%
Kraft Heinz Co/The	KHC	1228.3	33.09	40,644	0.14%	4.84%	3.92%	0.0069%	0.0056%
American Tower Corp	AMT	466.2	181.32	84,523	0.30%	3.46%	13.29%	0.0102%	0.0393%
Regeneron Pharmaceuticals Inc	REGN	106.7	826.49	Excl.	Excl.	n/a	1.00%		
Amazon.com Inc	AMZN	10317.8	138.01	Excl.	Excl.	n/a	51.21%		
Jack Henry & Associates Inc	JKHY	72.9	156.78	11,435	0.04%	1.33%	7.41%	0.0005%	0.0030%
Ralph Lauren Corp	RL	40.4	116.63	4,710	0.02%	2.57%	10.73%	0.0004%	0.0018%
Boston Properties Inc	BXP	156.9	66.77	10,474	0.04%	5.87%	3.79%	0.0021%	0.0014%
Amphenol Corp	APH	596.5	88.38	52,715	0.18%	0.95%	5.46%	0.0018%	0.0101%
Howmet Aerospace Inc	HWM	412.2	49.47	20,392	0.07%	0.32%	19.27%	0.0002%	0.0137%
Pioneer Natural Resources Co	PXD	233.1	237.93	55,471	0.19%	3.09%	-0.73%	0.0060%	-0.0014%
Valero Energy Corp	VLO	353.1	129.90	45,872	0.16%	3.14%	-7.69%	0.0050%	-0.0123%
Synopsys Inc	SNPS	152.1	458.89	Excl.	Excl.	n/a	16.27%		
Etsy Inc	ETSY	123.0	73.57	Excl.	Excl.	n/a	8.15%		
CH Robinson Worldwide Inc	CHRW	116.4	90.43	10,530	0.04%	2.70%	5.00%	0.0010%	0.0018%
Accenture PLC	ACN	630.8	323.77	204,232	0.71%	1.38%	10.00%	0.0099%	0.0714%
TransDigm Group Inc	TDG	55.2	903.85	Excl.	Excl.	n/a	26.65%		
Yum! Brands Inc	YUM	280.2	129.38	36,254	0.13%	1.87%	11.45%	0.0024%	0.0145%
Prologis Inc	PLD	923.9	124.20	114,744	0.40%	2.80%	8.95%	0.0112%	0.0359%
FirstEnergy Corp	FE	573.4	36.07	20,681	0.07%	4.32%	-6.66%	0.0031%	-0.0048%
VeriSign Inc	VRSN	103.1	207.79	Excl.	Excl.	n/a	12.30%		
Quanta Services Inc	PWR	145.2	209.87	30,473	0.11%	0.15%	8.00%	0.0002%	0.0085%
Henry Schein Inc	HSIC	130.6	76.54	Excl.	Excl.	n/a	5.16%		

U.S. Market DCF Calculation as of August 31, 2023

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast US Government 30 Year Yield	[14] Equity Risk Premium
S&P 500 INDEX	**1.93%**	**2.04%**	**12.26%**	**14.31%**	**3.98%**	**10.33%**

Company	Ticker	[5] Shares Outstanding (million)	[6] Price ($)	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Ameren Corp	AEE	262.5	79.27	20,806	0.07%	3.18%	6.93%	0.0023%	0.0050%
ANSYS Inc	ANSS	86.8	318.87	Excl.	Excl.	n/a	11.14%		
FactSet Research Systems Inc	FDS	38.1	436.41	16,647	0.06%	0.90%	11.97%	0.0005%	0.0070%
NVIDIA Corp	NVDA	2470.0	493.55	1,219,069	4.26%	0.03%	56.84%	0.0014%	2.4211%
Sealed Air Corp	SEE	144.4	37.06	5,352	0.02%	2.16%	0.93%	0.0004%	0.0002%
Cognizant Technology Solutions Corp	CTSH	505.0	71.61	36,166	0.13%	1.62%	12.00%	0.0020%	0.0152%
Intuitive Surgical Inc	ISRG	351.4	312.68	Excl.	Excl.	n/a	16.14%		
Take-Two Interactive Software Inc	TTWO	169.8	142.20	Excl.	Excl.	n/a	53.59%		
Republic Services Inc	RSG	316.3	144.13	45,592	0.16%	1.48%	9.26%	0.0024%	0.0148%
eBay Inc	EBAY	532.2	44.78	23,830	0.08%	2.23%	6.50%	0.0019%	0.0054%
Goldman Sachs Group Inc/The	GS	329.7	327.71	108,036	0.38%	3.36%	9.00%	0.0127%	0.0340%
SBA Communications Corp	SBAC	108.4	224.53	Excl.	Excl.	1.51%	n/a		
Sempra	SRE	629.3	70.22	44,190	0.15%	3.39%	3.45%	0.0052%	0.0053%
Moody's Corp	MCO	183.5	336.80	61,803	0.22%	0.91%	13.87%	0.0020%	0.0299%
ON Semiconductor Corp	ON	431.5	98.46	Excl.	Excl.	n/a	8.50%		
Booking Holdings Inc	BKNG	35.7	3105.03	Excl.	Excl.	n/a	20.00%		
F5 Inc	FFIV	59.3	163.66	Excl.	Excl.	n/a	10.19%		
Akamai Technologies Inc	AKAM	151.7	105.09	Excl.	Excl.	n/a	10.00%		
Charles River Laboratories International Inc	CRL	51.3	206.82	Excl.	Excl.	n/a	14.00%		
MarketAxess Holdings Inc	MKTX	37.7	240.93	Excl.	Excl.	1.20%	n/a		
Devon Energy Corp	DVN	640.7	51.09	32,733	0.11%	3.84%	-4.00%	0.0044%	-0.0046%
Bio-Techne Corp	TECH	158.2	78.40	Excl.	Excl.	0.41%	n/a		
Alphabet Inc	GOOGL	5933.0	136.17	Excl.	Excl.	n/a	18.01%		
Teleflex Inc	TFX	47.0	212.74	9,997	0.03%	0.64%	7.03%	0.0002%	0.0025%
Bunge Ltd	BG	150.6	114.32	17,221	0.06%	2.32%	-5.14%	0.0014%	-0.0031%
Allegion plc	ALLE	87.8	113.81	9,990	0.03%	1.58%	5.43%	0.0006%	0.0019%
Netflix Inc	NFLX	443.1	433.68	Excl.	Excl.	n/a	32.28%		
Agilent Technologies Inc	A	292.6	121.07	35,424	0.12%	0.74%	11.00%	0.0009%	0.0136%
Warner Bros Discovery Inc	WBD	2437.4	13.14	Excl.	Excl.	n/a	n/a		
Elevance Health Inc	ELV	235.6	442.01	104,159	0.36%	1.34%	12.13%	0.0049%	0.0441%
Trimble Inc	TRMB	248.3	54.79	Excl.	Excl.	n/a	n/a		
CME Group Inc	CME	359.7	202.68	72,913	0.25%	2.17%	6.14%	0.0055%	0.0156%
Juniper Networks Inc	JNPR	321.4	29.12	9,358	0.03%	3.02%	7.89%	0.0010%	0.0026%
BlackRock Inc	BLK	149.3	700.54	104,593	0.37%	2.85%	9.20%	0.0104%	0.0336%
DTE Energy Co	DTE	206.1	103.38	Excl.	Excl.	3.69%	n/a		
Nasdaq Inc	NDAQ	491.3	52.48	25,784	0.09%	1.68%	2.68%	0.0015%	0.0024%
Celanese Corp	CE	108.9	126.36	13,755	0.05%	2.22%	3.07%	0.0011%	0.0015%
Philip Morris International Inc	PM	1552.3	96.06	149,118	0.52%	5.29%	7.99%	0.0276%	0.0416%
Salesforce Inc	CRM	973.0	221.46	Excl.	Excl.	n/a	21.67%		
Ingersoll Rand Inc	IR	404.4	69.61	Excl.	Excl.	0.11%	n/a		
Roper Technologies Inc	ROP	106.7	499.06	Excl.	Excl.	0.55%	n/a		
Huntington Ingalls Industries Inc	HII	39.9	220.32	8,784	0.03%	2.25%	40.00%	0.0007%	0.0123%
MetLife Inc	MET	752.0	63.34	47,633	0.17%	3.28%	13.07%	0.0055%	0.0218%
Tapestry Inc	TPR	227.4	33.32	7,578	0.03%	4.20%	14.00%	0.0011%	0.0037%
CSX Corp	CSX	2006.3	30.20	60,591	0.21%	1.46%	3.11%	0.0031%	0.0066%
Edwards Lifesciences Corp	EW	607.9	76.47	Excl.	Excl.	n/a	10.65%		
Ameriprise Financial Inc	AMP	102.6	337.58	34,644	0.12%	1.60%	17.59%	0.0019%	0.0213%
Zebra Technologies Corp	ZBRA	51.3	275.01	Excl.	Excl.	n/a	n/a		
Zimmer Biomet Holdings Inc	ZBH	209.0	119.12	24,892	0.09%	0.81%	9.48%	0.0007%	0.0082%
CBRE Group Inc	CBRE	309.8	85.05	Excl.	Excl.	n/a	n/a		
Camden Property Trust	CPT	106.8	107.62	11,491	0.04%	3.72%	7.34%	0.0015%	0.0029%

U.S. Market DCF Calculation as of August 31, 2023

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast US Government 30 Year Yield	[14] Equity Risk Premium
S&P 500 INDEX	**1.93%**	**2.04%**	**12.26%**	**14.31%**	**3.98%**	**10.33%**

Company	Ticker	[5] Shares Outstanding (million)	[6] Price ($)	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Mastercard Inc	MA	934.8	412.64	385,756	1.35%	0.55%	18.18%	0.0074%	0.2450%
CarMax Inc	KMX	158.2	81.68	Excl.	Excl.	n/a	15.54%		
Intercontinental Exchange Inc	ICE	560.3	117.99	66,110	0.23%	1.42%	9.87%	0.0033%	0.0228%
Fidelity National Information Services Inc	FIS	592.5	55.86	33,095	0.12%	3.72%	2.68%	0.0043%	0.0031%
Chipotle Mexican Grill Inc	CMG	27.6	1926.64	Excl.	Excl.	n/a	26.95%		
Wynn Resorts Ltd	WYNN	113.9	101.38	Excl.	Excl.	0.99%	n/a		
Live Nation Entertainment Inc	LYV	230.2	84.53	Excl.	Excl.	n/a	n/a		
Assurant Inc	AIZ	53.0	139.33	7,388	0.03%	2.01%	13.68%	0.0005%	0.0035%
NRG Energy Inc	NRG	229.1	37.55	8,603	0.03%	4.02%	4.03%	0.0012%	0.0012%
Regions Financial Corp	RF	938.4	18.34	17,210	0.06%	5.23%	2.08%	0.0031%	0.0012%
Monster Beverage Corp	MNST	1047.5	57.41	Excl.	Excl.	n/a	15.05%		
Mosaic Co/The	MOS	332.3	38.85	12,909	0.05%	2.06%	38.00%	0.0009%	0.0171%
Baker Hughes Co	BKR	1009.7	36.19	36,539	0.13%	2.21%	57.62%	0.0028%	0.0736%
Expedia Group Inc	EXPE	137.8	108.39	Excl.	Excl.	n/a	17.50%		
CF Industries Holdings Inc	CF	192.9	77.07	14,871	0.05%	2.08%	44.50%	0.0011%	0.0231%
Leidos Holdings Inc	LDOS	137.4	97.51	13,393	0.05%	1.48%	6.45%	0.0007%	0.0030%
APA Corp	APA	307.3	43.84	13,470	0.05%	2.28%	-4.03%	0.0011%	-0.0019%
Alphabet Inc	GOOG	5801.0	137.35	Excl.	Excl.	n/a	18.01%		
First Solar Inc	FSLR	106.8	189.12	Excl.	Excl.	n/a	19.80%		
TE Connectivity Ltd	TEL	313.9	132.39	41,562	0.15%	1.78%	3.10%	0.0026%	0.0045%
Cooper Cos Inc/The	COO	49.5	369.99	18,323	0.06%	0.02%	7.00%	0.0000%	0.0045%
Discover Financial Services	DFS	249.9	90.07	22,513	0.08%	3.11%	6.93%	0.0024%	0.0055%
Linde PLC	LIN	487.9	387.04	188,855	0.66%	1.32%	9.20%	0.0087%	0.0607%
Visa Inc	V	1606.8	245.68	394,756	1.38%	0.73%	14.91%	0.0101%	0.2056%
Mid-America Apartment Communities Inc	MAA	116.7	145.23	Excl.	Excl.	3.86%	n/a		
Xylem Inc/NY	XYL	240.8	103.54	Excl.	Excl.	1.27%	n/a		
Marathon Petroleum Corp	MPC	399.8	142.77	57,086	0.20%	2.10%	32.45%	0.0042%	0.0647%
Tractor Supply Co	TSCO	108.8	218.50	23,775	0.08%	1.89%	10.00%	0.0016%	0.0083%
Advanced Micro Devices Inc	AMD	1615.7	105.72	Excl.	Excl.	n/a	26.26%		
ResMed Inc	RMD	147.1	159.59	23,471	0.08%	1.20%	9.21%	0.0010%	0.0076%
Mettler-Toledo International Inc	MTD	21.9	1213.48	Excl.	Excl.	n/a	9.75%		
Jacobs Solutions Inc	J	125.9	134.82	16,976	0.06%	0.77%	9.26%	0.0005%	0.0055%
Copart Inc	CPRT	954.9	44.83	Excl.	Excl.	n/a	10.00%		
VICI Properties Inc	VICI	1013.4	30.84	31,254	0.11%	5.06%	6.33%	0.0055%	0.0069%
Albemarle Corp	ALB	117.3	198.71	23,318	0.08%	0.81%	31.93%	0.0007%	0.0260%
Fortinet Inc	FTNT	785.3	60.21	Excl.	Excl.	n/a	18.00%		
Moderna Inc	MRNA	380.6	113.07	Excl.	Excl.	n/a	-60.35%		
Essex Property Trust Inc	ESS	64.2	238.39	15,301	0.05%	3.88%	9.80%	0.0021%	0.0052%
CoStar Group Inc	CSGP	408.3	81.99	Excl.	Excl.	n/a	20.00%		
Realty Income Corp	O	708.8	56.04	Excl.	Excl.	5.47%	n/a		
Westrock Co	WRK	256.3	32.71	8,383	0.03%	3.36%	-6.74%	0.0010%	-0.0020%
Westinghouse Air Brake Technologies Corp	WAB	179.1	112.52	20,156	0.07%	0.60%	11.33%	0.0004%	0.0080%
Pool Corp	POOL	39.1	365.60	14,277	0.05%	1.20%	-4.92%	0.0006%	-0.0025%
Western Digital Corp	WDC	321.9	45.00	Excl.	Excl.	n/a	-22.46%		
PepsiCo Inc	PEP	1376.6	177.92	244,921	0.86%	2.84%	8.64%	0.0243%	0.0739%
Diamondback Energy Inc	FANG	178.8	151.78	27,141	0.09%	2.21%	8.97%	0.0021%	0.0085%
Palo Alto Networks Inc	PANW	305.9	243.30	Excl.	Excl.	n/a	20.50%		
ServiceNow Inc	NOW	204.0	588.83	Excl.	Excl.	n/a	30.00%		
Church & Dwight Co Inc	CHD	246.0	96.77	23,810	0.08%	1.13%	5.85%	0.0009%	0.0049%
Federal Realty Investment Trust	FRT	81.5	97.94	7,984	0.03%	4.45%	6.85%	0.0012%	0.0019%
MGM Resorts International	MGM	350.9	43.98	Excl.	Excl.	n/a	n/a		

U.S. Market DCF Calculation as of August 31, 2023

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500 INDEX	**1.93%**	**2.04%**	**12.26%**	**14.31%**	**3.98%**	**10.33%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
American Electric Power Co Inc	AEP	515.2	78.40	Excl.	Excl.	4.23%	n/a		
SolarEdge Technologies Inc	SEDG	56.6	162.57	Excl.	Excl.	n/a	26.90%		
Invitation Homes Inc	INVH	612.0	34.09	20,862	0.07%	3.05%	7.96%	0.0022%	0.0058%
PTC Inc	PTC	118.8	147.17	Excl.	Excl.	n/a	16.99%		
JB Hunt Transport Services Inc	JBHT	103.3	187.88	19,416	0.07%	0.89%	15.00%	0.0006%	0.0102%
Lam Research Corp	LRCX	132.5	702.40	93,076	0.33%	1.14%	12.20%	0.0037%	0.0397%
Mohawk Industries Inc	MHK	63.7	101.39	Excl.	Excl.	n/a	-1.83%		
GE HealthCare Technologies Inc	GEHC	454.8	70.45	32,043	0.11%	0.17%	12.75%	0.0002%	0.0143%
Pentair PLC	PNR	165.1	70.26	11,601	0.04%	1.25%	6.14%	0.0005%	0.0025%
Vertex Pharmaceuticals Inc	VRTX	258.1	348.34	Excl.	Excl.	n/a	13.72%		
Amcor PLC	AMCR	1448.5	9.74	14,108	0.05%	5.03%	2.20%	0.0025%	0.0011%
Meta Platforms Inc	META	2222.6	295.89	Excl.	Excl.	n/a	27.44%		
T-Mobile US Inc	TMUS	1176.5	136.25	Excl.	Excl.	n/a	5.00%		
United Rentals Inc	URI	68.3	476.54	32,540	0.11%	1.24%	20.04%	0.0014%	0.0228%
Honeywell International Inc	HON	664.0	187.94	124,785	0.44%	2.19%	9.50%	0.0096%	0.0414%
Alexandria Real Estate Equities Inc	ARE	173.0	116.34	20,130	0.07%	4.26%	4.05%	0.0030%	0.0028%
Delta Air Lines Inc	DAL	643.4	42.88	27,590	0.10%	0.93%	37.89%	0.0009%	0.0365%
Seagate Technology Holdings PLC	STX	207.4	70.79	14,681	0.05%	3.96%	1.21%	0.0020%	0.0006%
United Airlines Holdings Inc	UAL	326.7	49.81	Excl.	Excl.	n/a	n/a		
News Corp	NWS	191.8	22.00	4,220	0.01%	0.91%	8.00%	0.0001%	0.0012%
Centene Corp	CNC	541.5	61.65	Excl.	Excl.	n/a	8.43%		
Martin Marietta Materials Inc	MLM	61.8	446.41	27,590	0.10%	0.66%	19.03%	0.0006%	0.0183%
Teradyne Inc	TER	154.0	107.87	16,613	0.06%	0.41%	15.00%	0.0002%	0.0087%
PayPal Holdings Inc	PYPL	1098.0	62.51	Excl.	Excl.	n/a	15.96%		
Tesla Inc	TSLA	3174.0	258.08	Excl.	Excl.	n/a	16.00%		
Arch Capital Group Ltd	ACGL	373.0	76.86	Excl.	Excl.	n/a	14.50%		
Dow Inc	DOW	703.1	54.56	38,360	0.13%	5.13%	2.78%	0.0069%	0.0037%
Everest Group Ltd	EG	43.4	360.68	15,655	0.05%	1.83%	33.24%	0.0010%	0.0182%
Teledyne Technologies Inc	TDY	47.1	418.30	Excl.	Excl.	n/a	6.36%		
News Corp	NWSA	379.6	21.49	8,157	0.03%	0.93%	8.00%	0.0003%	0.0023%
Exelon Corp	EXC	994.3	40.12	39,891	0.14%	3.59%	5.30%	0.0050%	0.0074%
Global Payments Inc	GPN	260.0	126.69	32,939	0.12%	0.79%	13.63%	0.0009%	0.0157%
Crown Castle Inc	CCI	433.7	100.50	Excl.	Excl.	6.23%	n/a		
Aptiv PLC	APTV	282.8	101.45	Excl.	Excl.	n/a	12.44%		
Align Technology Inc	ALGN	76.5	370.14	Excl.	Excl.	n/a	17.54%		
Illumina Inc	ILMN	158.3	165.22	Excl.	Excl.	n/a	-32.22%		
Kenvue Inc	KVUE	1914.9	23.05	Excl.	Excl.	3.47%	n/a		
Targa Resources Corp	TRGP	223.7	86.25	19,295	0.07%	2.32%	15.00%	0.0016%	0.0101%
LKQ Corp	LKQ	267.6	52.53	Excl.	Excl.	2.09%	n/a		
Zoetis Inc	ZTS	460.3	190.51	87,695	0.31%	0.79%	10.91%	0.0024%	0.0334%
Equinix Inc	EQIX	93.6	781.38	73,110	0.26%	1.75%	15.43%	0.0045%	0.0394%
Digital Realty Trust Inc	DLR	302.7	131.72	39,873	0.14%	3.70%	6.59%	0.0052%	0.0092%
Molina Healthcare Inc	MOH	58.3	310.12	Excl.	Excl.	n/a	11.74%		
Las Vegas Sands Corp	LVS	764.4	54.86	Excl.	Excl.	1.46%	n/a		
Average for Companies Paying Dividends with Long-Term Growth Estimates					**100.00%**			**1.93%**	**12.26%**

U.S. Market DCF Calculation as of August 31, 2023

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500 INDEX	**1.93%**	**2.04%**	**12.26%**	**14.31%**	**3.98%**	**10.33%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate

Notes:
[1] Equals sum of Column [11]
[2] Equals [1] x (1 + 0.5 x [3])
[3] Equals sum of Column [12]
[4] Equals [2] + [3]
[5] Source: Bloomberg Finance L.P., as of August 31, 2023
[6] Source: Bloomberg Finance L.P., as of August 31, 2023
[7] Equals Column [5] x Column [6]. Excludes non-dividend paying companies and companies with no long-term growth estimates.
[8] Equals weight in index based on market capitalization. Excludes non-dividend paying companies and companies with no long-term growth estimates.
[9] Source: Bloomberg Finance L.P., as of August 31, 2023
[10] Source: Bloomberg Finance L.P., as of August 31, 2023
[11] Equals Column [8] x Column [9]
[12] Equals Column [8] x Column [10]
[13] Source: Equals average long-term Consensus Forecast of 10-year government bond yields for the period 2024-2026 as of April 11, 2023 (pp. 3, 28), plus the average spread between 10- and 30-year bond for the past 10 years.
[14] Equals [4] - [13]

Capital Asset Pricing Model - Average MRP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Canadian Proxy Group	Ticker	Bloomberg	Value Line	Average Beta	Risk Free Rate	Average Market Risk Premium	Basic CAPM Calculation	Flotation Cost	Total CAPM
Algonquin Power & Utilities Corp.	AQN	0.99	n/a	0.99	3.52%	6.99%	10.44%	0.50%	10.94%
AltaGas Ltd.	ALA	1.13	n/a	1.13	3.52%	6.99%	11.41%	0.50%	11.91%
Canadian Utilities Limited	CU	0.84	n/a	0.84	3.52%	6.99%	9.39%	0.50%	9.89%
Emera Inc.	EMA	0.70	0.70	0.70	3.52%	6.99%	8.39%	0.50%	8.89%
Enbridge Inc.	ENB	0.93	0.85	0.89	3.52%	6.99%	9.74%	0.50%	10.24%
HydroOne Ltd.	H	0.66	n/a	0.66	3.52%	6.99%	8.15%	0.50%	8.65%
MEAN		0.87	0.78	0.87			9.59%		10.09%

US Electric Proxy Group	Ticker	Bloomberg	Value Line	Average Beta	Risk Free Rate	Average Market Risk Premium	Basic CAPM Calculation	Flotation Cost	Total CAPM
Alliant Energy Corporation	LNT	0.87	0.85	0.86	3.98%	6.99%	9.99%	0.50%	10.49%
American Electric Power Company, Inc.	AEP	0.83	0.75	0.79	3.98%	6.99%	9.48%	0.50%	9.98%
Duke Energy Corporation	DUK	0.81	0.85	0.83	3.98%	6.99%	9.77%	0.50%	10.27%
Entergy Corporation	ETR	0.94	0.90	0.92	3.98%	6.99%	10.42%	0.50%	10.92%
Evergy, Inc.	EVRG	0.87	0.90	0.88	3.98%	6.99%	10.15%	0.50%	10.65%
Eversource Energy	ES	0.88	0.90	0.89	3.98%	6.99%	10.20%	0.50%	10.70%
NextEra Energy Inc.	NEE	0.89	0.95	0.92	3.98%	6.99%	10.41%	0.50%	10.91%
OGE Corp	OGE	1.00	1.00	1.00	3.98%	6.99%	10.95%	0.50%	11.45%
Pinnacle West Capital Corporation	PNW	0.92	0.90	0.91	3.98%	6.99%	10.34%	0.50%	10.84%
Portland General Electric Company	POR	0.86	0.90	0.88	3.98%	6.99%	10.12%	0.50%	10.62%
MEAN		0.89	0.89	0.89			10.18%		10.68%

Capital Asset Pricing Model - Average MRP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
North American Electric Proxy Group	Ticker	Bloomberg	Value Line	Average Beta	Risk Free Rate	Average Market Risk Premium	Basic CAPM Calculation	Flotation Cost	Total CAPM
Algonquin Power & Utilities Corp.	AQN	0.99	n/a	0.99	3.52%	6.99%	10.44%	0.50%	10.94%
Canadian Utilities Limited	CU	0.84	n/a	0.84	3.52%	6.99%	9.39%	0.50%	9.89%
Emera Inc.	EMA	0.70	0.70	0.70	3.52%	6.99%	8.39%	0.50%	8.89%
HydroOne Inc.	H	0.66	n/a	0.66	3.52%	6.99%	8.15%	0.50%	8.65%
Alliant Energy Corporation	LNT	0.87	0.85	0.86	3.98%	6.99%	9.99%	0.50%	10.49%
American Electric Power Company, Inc.	AEP	0.83	0.75	0.79	3.98%	6.99%	9.48%	0.50%	9.98%
Duke Energy Corporation	DUK	0.81	0.85	0.83	3.98%	6.99%	9.77%	0.50%	10.27%
Entergy Corporation	ETR	0.94	0.90	0.92	3.98%	6.99%	10.42%	0.50%	10.92%
Evergy, Inc.	EVRG	0.87	0.90	0.88	3.98%	6.99%	10.15%	0.50%	10.65%
Eversource Energy	ES	0.88	0.90	0.89	3.98%	6.99%	10.20%	0.50%	10.70%
NextEra Energy Inc.	NEE	0.89	0.95	0.92	3.98%	6.99%	10.41%	0.50%	10.91%
OGE Corp	OGE	1.00	1.00	1.00	3.98%	6.99%	10.95%	0.50%	11.45%
Pinnacle West Capital Corporation	PNW	0.92	0.90	0.91	3.98%	6.99%	10.34%	0.50%	10.84%
Portland General Electric Company	POR	0.86	0.90	0.88	3.98%	6.99%	10.12%	0.50%	10.62%
MEAN		0.86	0.87	0.86			9.87%		10.37%

Notes:
[1] Source: Bloomberg Professional as of August 31, 2023; weekly changes in equity stock price against SPX index (U.S.) or SPTSX (Canada) Index for the past five years
[2] Source: Value Line as of August 31, 2023
[3] Equals mean of [1] and [2]
[4] Source: Equals average long-term Consensus Forecast of 10-year government bond yields for the period 2024-2026 as of April 11, 2023 (pp. 3, 28), plus the average spread between 10- and 30-year bond for the past 10 years.
[5] Source: Average of Bloomberg TSX total return less [4] as of June 30, 2023, the Bloomberg S&P 500 total return less [4] as of August 31, 2023, the 1919-2022 Canada historical risk premium of 5.62%, and the US historical risk premium of 7.17%, as sourced by Duff and Phelps
[6] Equals [4] + ([3] x [5])
[7] The Board allows 50 bps for flotation costs and financial flexibility.
[8] Equals [6] + [7]

Capital Asset Pricing Model - Historical MRP

Canadian Proxy Group	Ticker	[1] Bloomberg	[2] Value Line	[3] Average Beta	[4] Risk Free Rate	[5] Average Market Risk Premium	[6] Basic CAPM Calculation	[7] Flotation Cost	[8] Total CAPM
Algonquin Power & Utilities Corp.	AQN	0.99	n/a	0.99	3.52%	6.39%	9.85%	0.50%	10.35%
AltaGas Ltd.	ALA	1.13	n/a	1.13	3.52%	6.39%	10.73%	0.50%	11.23%
Canadian Utilities Limited	CU	0.84	n/a	0.84	3.52%	6.39%	8.89%	0.50%	9.39%
Emera Inc.	EMA	0.70	0.70	0.70	3.52%	6.39%	7.98%	0.50%	8.48%
Enbridge Inc.	ENB	0.93	0.85	0.89	3.52%	6.39%	9.21%	0.50%	9.71%
HydroOne Ltd.	H	0.66	n/a	0.66	3.52%	6.39%	7.76%	0.50%	8.26%
MEAN		0.87	0.78	0.87			9.07%		9.57%

US Electric Proxy Group	Ticker	Bloomberg	Value Line	Average Beta	Risk Free Rate	Average Market Risk Premium	Basic CAPM Calculation	Flotation Cost	Total CAPM
Alliant Energy Corporation	LNT	0.87	0.85	0.86	3.98%	6.39%	9.47%	0.50%	9.97%
American Electric Power Company, Inc.	AEP	0.83	0.75	0.79	3.98%	6.39%	9.01%	0.50%	9.51%
Duke Energy Corporation	DUK	0.81	0.85	0.83	3.98%	6.39%	9.27%	0.50%	9.77%
Entergy Corporation	ETR	0.94	0.90	0.92	3.98%	6.39%	9.87%	0.50%	10.37%
Evergy, Inc.	EVRG	0.87	0.90	0.88	3.98%	6.39%	9.63%	0.50%	10.13%
Eversource Energy	ES	0.88	0.90	0.89	3.98%	6.39%	9.67%	0.50%	10.17%
NextEra Energy Inc.	NEE	0.89	0.95	0.92	3.98%	6.39%	9.86%	0.50%	10.36%
OGE Corp	OGE	1.00	1.00	1.00	3.98%	6.39%	10.35%	0.50%	10.85%
Pinnacle West Capital Corporation	PNW	0.92	0.90	0.91	3.98%	6.39%	9.80%	0.50%	10.30%
Portland General Electric Company	POR	0.86	0.90	0.88	3.98%	6.39%	9.59%	0.50%	10.09%
MEAN		0.89	0.89	0.89			9.65%		10.15%

Capital Asset Pricing Model - Historical MRP

North American Electric Proxy Group	Ticker	[1] Bloomberg	[2] Value Line	[3] Average Beta	[4] Risk Free Rate	[5] Average Market Risk Premium	[6] Basic CAPM Calculation	[7] Flotation Cost	[8] Total CAPM
Algonquin Power & Utilities Corp.	AQN	0.99	n/a	0.99	3.52%	6.39%	9.85%	0.50%	10.35%
Canadian Utilities Limited	CU	0.84	n/a	0.84	3.52%	6.39%	8.89%	0.50%	9.39%
Emera Inc.	EMA	0.70	0.70	0.70	3.52%	6.39%	7.98%	0.50%	8.48%
HydroOne Inc.	H	0.66	n/a	0.66	3.52%	6.39%	7.76%	0.50%	8.26%
Alliant Energy Corporation	LNT	0.87	0.85	0.86	3.98%	6.39%	9.47%	0.50%	9.97%
American Electric Power Company, Inc.	AEP	0.83	0.75	0.79	3.98%	6.39%	9.01%	0.50%	9.51%
Duke Energy Corporation	DUK	0.81	0.85	0.83	3.98%	6.39%	9.27%	0.50%	9.77%
Entergy Corporation	ETR	0.94	0.90	0.92	3.98%	6.39%	9.87%	0.50%	10.37%
Evergy, Inc.	EVRG	0.87	0.90	0.88	3.98%	6.39%	9.63%	0.50%	10.13%
Eversource Energy	ES	0.88	0.90	0.89	3.98%	6.39%	9.67%	0.50%	10.17%
NextEra Energy Inc.	NEE	0.89	0.95	0.92	3.98%	6.39%	9.86%	0.50%	10.36%
OGE Corp	OGE	1.00	1.00	1.00	3.98%	6.39%	10.35%	0.50%	10.85%
Pinnacle West Capital Corporation	PNW	0.92	0.90	0.91	3.98%	6.39%	9.80%	0.50%	10.30%
Portland General Electric Company	POR	0.86	0.90	0.88	3.98%	6.39%	9.59%	0.50%	10.09%
MEAN		0.86	0.87	0.86			9.36%		9.86%

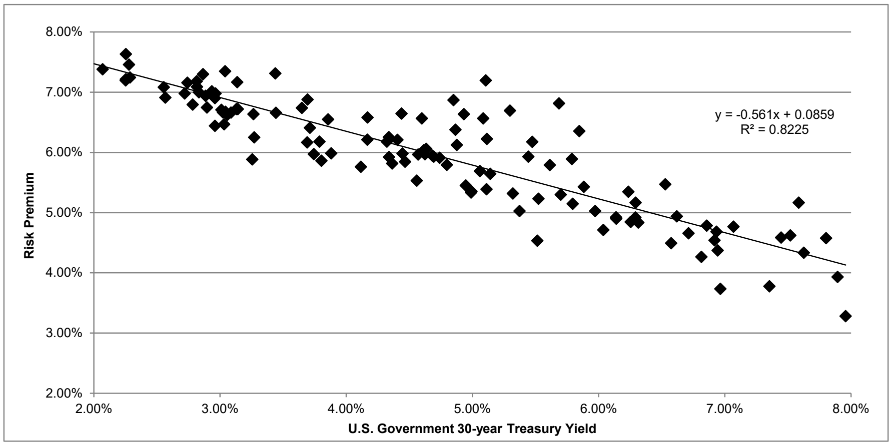
Notes:
[1] Source: Bloomberg Professional as of August 31, 2023; weekly changes in equity stock price against SPX index (U.S.) or SPTSX (Canada) Index for the past five years
[2] Source: Value Line as of August 31, 2023
[3] Equals mean of [1] and [2]
[4] Source: Equals average long-term Consensus Forecast of 10-year government bond yields for the period 2024-2026 as of April 11, 2023 (pp. 3, 28), plus the average spread between 10- and 30-year bond for the past 10 years.
[5] Source: Average of Bloomberg TSX total return less [4] as of June 30, 2023, the Bloomberg S&P 500 total return less [4] as of August 31, 2023, the 1919-2022 Canada historical risk premium of 5.62%, and the US historical risk premium of 7.17%, as sourced by Duff and Phelps
[6] Equals [4] + ([3] x [5])
[7] The Board allows 50 bps for flotation costs and financial flexibility.
[8] Equals [6] + [7]

Risk Premium -- Electric Utilities

	[1] Average Authorized Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1992.1	12.38%	7.80%	4.58%
1992.2	11.83%	7.89%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.77%
1993.2	11.64%	6.86%	4.79%
1993.3	11.15%	6.31%	4.84%
1993.4	11.04%	6.14%	4.90%
1994.1	11.07%	6.57%	4.49%
1994.2	11.13%	7.35%	3.78%
1994.3	12.75%	7.58%	5.17%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.34%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.71%	4.66%
1995.4	11.58%	6.23%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.96%	3.74%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.81%	4.27%
1997.2	11.62%	6.93%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.14%	4.92%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.47%	6.18%
1998.4	12.30%	5.10%	7.20%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.79%	5.15%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.25%	4.85%
2000.1	11.21%	6.29%	4.92%
2000.2	11.00%	5.97%	5.03%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.44%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.52%	5.23%
2001.4	11.99%	5.30%	6.70%
2002.1	10.05%	5.51%	4.54%
2002.2	11.41%	5.61%	5.79%
2002.3	11.65%	5.08%	6.57%
2002.4	11.57%	4.93%	6.64%
2003.1	11.72%	4.85%	6.87%
2003.2	11.16%	4.60%	6.56%
2003.3	10.50%	5.11%	5.39%
2003.4	11.34%	5.11%	6.23%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.32%	5.32%
2004.3	10.75%	5.06%	5.69%
2004.4	11.24%	4.86%	6.38%
2005.1	10.63%	4.69%	5.93%
2005.2	10.31%	4.47%	5.85%
2005.3	11.08%	4.44%	6.65%
2005.4	10.63%	4.68%	5.95%
2006.1	10.70%	4.63%	6.06%
2006.2	10.79%	5.14%	5.65%
2006.3	10.35%	4.99%	5.35%
2006.4	10.65%	4.74%	5.91%
2007.1	10.59%	4.80%	5.80%
2007.2	10.33%	4.99%	5.34%
2007.3	10.40%	4.95%	5.45%
2007.4	10.65%	4.61%	6.04%
2008.1	10.62%	4.41%	6.21%
2008.2	10.54%	4.57%	5.97%
2008.3	10.43%	4.44%	5.98%
2008.4	10.39%	3.65%	6.74%
2009.1	10.75%	3.44%	7.31%
2009.2	10.75%	4.17%	6.58%
2009.3	10.50%	4.32%	6.18%
2009.4	10.59%	4.34%	6.26%
2010.1	10.59%	4.62%	5.97%
2010.2	10.18%	4.36%	5.82%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.21%
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.69%	6.88%
2011.4	10.39%	3.04%	7.35%
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.93%	7.02%
2012.3	9.90%	2.74%	7.16%

Risk Premium -- Electric Utilities

	[1]	[2]	[3]
	Average Authorized Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%
2013.2	9.86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.17%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.26%	6.64%
2014.4	9.94%	2.96%	6.98%
2015.1	9.64%	2.55%	7.08%
2015.2	9.83%	2.88%	6.94%
2015.3	9.40%	2.96%	6.44%
2015.4	9.86%	2.96%	6.90%
2016.1	9.70%	2.72%	6.98%
2016.2	9.48%	2.57%	6.91%
2016.3	9.74%	2.28%	7.46%
2016.4	9.83%	2.83%	7.00%
2017.1	9.72%	3.04%	6.67%
2017.2	9.64%	2.90%	6.75%
2017.3	10.00%	2.82%	7.18%
2017.4	9.91%	2.82%	7.09%
2018.1	9.69%	3.02%	6.66%
2018.2	9.75%	3.09%	6.66%
2018.3	9.69%	3.06%	6.63%
2018.4	9.52%	3.27%	6.25%
2019.1	9.72%	3.01%	6.71%
2019.2	9.58%	2.78%	6.79%
2019.3	9.53%	2.29%	7.24%
2019.4	9.89%	2.25%	7.63%
2020.1	9.72%	1.89%	7.83%
2020.2	9.58%	1.38%	8.20%
2020.3	9.30%	1.37%	7.93%
2020.4	9.56%	1.62%	7.94%
2021.1	9.45%	2.07%	7.38%
2021.2	9.47%	2.25%	7.21%
2021.3	9.27%	1.93%	7.34%
2021.4	9.67%	1.94%	7.73%
2022.1	9.45%	2.25%	7.20%
2022.2	9.50%	3.03%	6.47%
2022.3	9.14%	3.26%	5.88%
2022.4	9.87%	3.88%	5.99%
2023.1	9.72%	3.74%	5.97%
2023.2	9.67%	3.80%	5.86%
2023.3	9.88%	4.12%	5.76%
AVERAGE	10.59%	4.54%	6.05%
MEDIAN	10.54%	4.57%	6.17%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.906919301
R Square	0.822502618
Adjusted R Square	0.821082639
Standard Error	0.004293073
Observations	127

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.010675591	0.010675591	579.23574	9.307E-49
Residual	125	0.00230381	1.84305E-05		
Total	126	0.0129794			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.085939721	0.00112394	76.46293083	8.0991E-107	0.083715305	0.08816414	0.083715305	0.088164137
X Variable 1	-0.56097978	0.023308779	-24.0673168	9.307E-49	-0.607110745	-0.5148488	-0.60711075	-0.51484881

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.21%	6.23%	10.44%
Blue Chip Near-Term Projected Forecast (Q4 2023 - Q4 2024) [5]	4.04%	6.33%	10.37%
Blue Chip Long-Term Projected Forecast (2025-2029) [6]	3.80%	6.46%	10.26%
AVERAGE			10.36%

Notes:
[1] Source: Regulatory Research Associates, rate cases through August 31, 2023
[2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, 30-day average as of August 31, 2023
[5] Source: Blue Chip Financial Forecasts, Vol. 42, No. 9, September 1, 2023 at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023 at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.085940 + (-0.560980 x Column [7])
[9] Equals Column [7] + Column [8]

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2023Q2	2023Q1	2022Q4	2022Q3	2022Q2	2022Q1	2021Q4	2021Q3	Average
Alliant Energy Corporation	LNT	52.35%	52.27%	52.60%	51.39%	52.65%	52.23%	51.32%	53.49%	52.29%
American Electric Power Company, Inc.	AEP	47.75%	48.17%	48.56%	48.33%	47.44%	48.08%	47.76%	47.16%	47.91%
Duke Energy Corporation	DUK	51.73%	51.80%	53.04%	53.72%	53.18%	52.23%	53.39%	53.27%	52.80%
Entergy Corporation	ETR	50.03%	49.16%	47.70%	47.53%	48.07%	44.27%	45.54%	46.94%	47.41%
Evergy, Inc.	EVRG	60.33%	60.88%	60.80%	62.19%	61.61%	60.68%	60.43%	60.28%	60.90%
Eversource Energy	ES	56.42%	55.68%	56.74%	54.61%	55.11%	55.31%	54.83%	53.80%	55.31%
NextEra Energy Inc	NEE	59.14%	61.16%	63.14%	62.70%	60.03%	58.48%	62.37%	63.53%	61.32%
OGE Energy Corp.	OGE	53.30%	53.22%	55.65%	55.42%	54.13%	53.59%	53.38%	53.16%	53.98%
Pinnacle West Capital Corporation	PNW	48.80%	50.82%	50.25%	52.38%	51.68%	51.76%	51.12%	51.13%	50.99%
Portland General Electric Company	POR	47.79%	47.10%	43.24%	45.61%	45.40%	45.14%	45.09%	44.79%	45.52%
MEAN		52.76%	53.03%	53.17%	53.39%	52.93%	52.18%	52.52%	52.76%	52.84%
LOW		47.75%	47.10%	43.24%	45.61%	45.40%	44.27%	45.09%	44.79%	45.52%
HIGH		60.33%	61.16%	63.14%	62.70%	61.61%	60.68%	62.37%	63.53%	61.32%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2023Q2	2023Q1	2022Q4	2022Q3	2022Q2	2022Q1	2021Q4	2021Q3	Average
Interstate Power and Light Company	LNT	50.60%	50.59%	50.55%	50.85%	50.36%	50.31%	50.22%	54.02%	50.94%
Wisconsin Power and Light Company	LNT	54.29%	54.12%	55.03%	52.03%	55.68%	54.83%	52.86%	52.76%	53.95%
AEP Texas, Inc.	AEP	43.19%	43.55%	42.07%	41.73%	39.30%	43.28%	42.81%	41.68%	42.20%
Appalachian Power Company	AEP	47.70%	48.37%	47.76%	47.00%	49.31%	48.93%	48.34%	48.01%	48.18%
Indiana Michigan Power Company	AEP	48.22%	47.89%	49.29%	48.97%	48.34%	47.96%	47.38%	47.48%	48.19%
Kentucky Power Company	AEP	43.47%	43.94%	43.82%	43.90%	45.25%	44.89%	44.17%	44.00%	44.18%
Kingsport Power Company	AEP	49.97%	49.57%	53.89%	53.51%	49.46%	49.39%	54.18%	53.66%	51.70%
Ohio Power Company	AEP	50.14%	51.81%	50.79%	50.34%	49.86%	49.35%	48.76%	44.68%	49.47%
Public Service Company of Oklahoma	AEP	50.51%	50.00%	55.70%	55.82%	49.15%	48.66%	54.36%	54.31%	52.31%
Southwestern Electric Power Company	AEP	50.85%	50.65%	52.54%	52.75%	52.10%	51.64%	48.70%	50.55%	51.22%
Wheeling Power Company	AEP	47.04%	49.60%	49.14%	52.37%	51.40%	54.10%	54.01%	54.00%	51.46%
Duke Energy Carolinas, LLC	DUK	50.77%	51.75%	52.78%	52.32%	51.46%	50.31%	52.05%	51.64%	51.64%
Duke Energy Florida, LLC	DUK	51.76%	51.29%	50.74%	54.76%	53.89%	53.15%	52.65%	55.67%	52.99%
Duke Energy Indiana, LLC	DUK	51.56%	51.08%	52.06%	53.47%	52.70%	52.90%	53.56%	55.08%	52.80%
Duke Energy Kentucky, Inc.	DUK	53.99%	53.64%	52.97%	52.75%	52.11%	53.63%	52.90%	52.62%	53.08%
Duke Energy Ohio, Inc.	DUK	60.53%	60.19%	65.87%	65.56%	65.06%	64.79%	64.40%	63.53%	63.74%
Duke Energy Progress, LLC	DUK	49.64%	49.28%	51.27%	50.81%	51.04%	49.29%	51.76%	49.33%	50.30%
Entergy Arkansas, Inc.	ETR	46.72%	45.35%	47.95%	47.85%	47.17%	46.98%	47.84%	47.97%	47.23%
Entergy Louisiana, LLC	ETR	51.63%	51.05%	47.17%	47.04%	48.16%	40.84%	43.08%	45.02%	46.75%
Entergy Mississippi, Inc.	ETR	46.98%	45.52%	46.43%	44.97%	43.91%	45.94%	45.53%	47.53%	45.85%
Entergy New Orleans, LLC	ETR	48.29%	48.30%	47.94%	47.81%	46.83%	46.10%	45.52%	49.94%	47.59%
Entergy Texas, Inc.	ETR	51.53%	50.74%	50.36%	50.98%	53.15%	52.21%	51.71%	51.18%	51.48%
Evergy Metro	EVRG	51.88%	55.06%	52.03%	53.21%	52.62%	51.85%	51.36%	51.20%	52.40%
Evergy Kansas South	EVRG	84.95%	83.79%	83.66%	83.73%	83.34%	83.22%	83.11%	83.27%	83.63%
Evergy Missouri West, Inc.	EVRG	54.99%	54.57%	54.41%	60.84%	59.64%	52.96%	52.01%	50.37%	54.97%
Westar Energy (KPL)	EVRG	56.24%	55.79%	58.03%	58.57%	58.22%	58.81%	58.52%	58.65%	57.85%
Connecticut Light and Power Company	ES	58.09%	57.89%	58.18%	57.82%	57.53%	56.87%	56.07%	55.21%	57.21%
NSTAR Electric Company	ES	56.54%	55.61%	56.32%	51.95%	53.53%	55.68%	55.58%	54.09%	54.91%
Public Service Company of New Hampshire	ES	51.67%	49.83%	53.77%	53.04%	52.53%	49.56%	49.10%	48.91%	51.05%
Florida Power & Light Company	NEE	59.14%	61.16%	63.14%	62.70%	60.03%	58.48%	62.12%	63.35%	61.26%
Gulf Power Company	NEE							64.92%	65.27%	65.10%
Oklahoma Gas and Electric Company	OGE	53.30%	53.22%	55.65%	55.42%	54.13%	53.59%	53.38%	53.16%	53.98%
Pinnacle West Capital Corporation	PNW	48.80%	50.82%	50.25%	52.38%	51.68%	51.76%	51.12%	51.13%	50.99%
Portland General Electric Company	POR	47.79%	47.10%	43.24%	45.61%	45.40%	45.14%	45.09%	44.79%	45.52%

Notes:

[1] Ratios are weighted by actual common capital and long-term debt of Operating Subsidiaries.

[2] Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.
Analysis excludes natural gas subsidiaries.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2023Q2	2023Q1	2022Q4	2022Q3	2022Q2	2022Q1	2021Q4	2021Q3	Average
Alliant Energy Corporation	LNT	47.65%	47.73%	47.40%	48.61%	47.35%	47.77%	48.68%	46.51%	47.71%
American Electric Power Company, Inc.	AEP	52.25%	51.83%	51.44%	51.67%	52.56%	51.92%	52.24%	52.84%	52.09%
Duke Energy Corporation	DUK	48.27%	48.20%	46.96%	46.28%	46.82%	47.77%	46.61%	46.73%	47.20%
Entergy Corporation	ETR	49.97%	50.84%	52.30%	52.47%	51.93%	55.73%	54.46%	53.06%	52.59%
Evergy, Inc.	EVRG	39.67%	39.12%	39.20%	37.81%	38.39%	39.32%	39.57%	39.72%	39.10%
Eversource Energy	ES	43.58%	44.32%	43.26%	45.39%	44.89%	44.69%	45.17%	46.20%	44.69%
NextEra Energy Inc	NEE	40.86%	38.84%	36.86%	37.30%	39.97%	41.52%	37.63%	36.47%	38.68%
OGE Energy Corp.	OGE	46.70%	46.78%	44.35%	44.58%	45.87%	46.41%	46.62%	46.84%	46.02%
Pinnacle West Capital Corporation	PNW	51.20%	49.18%	49.75%	47.62%	48.32%	48.24%	48.88%	48.87%	49.01%
Portland General Electric Company	POR	52.21%	52.90%	56.76%	54.39%	54.60%	54.86%	54.91%	55.21%	54.48%
MEAN		47.24%	46.97%	46.83%	46.61%	47.07%	47.82%	47.48%	47.24%	47.16%
LOW		39.67%	38.84%	36.86%	37.30%	38.39%	39.32%	37.63%	36.47%	38.68%
HIGH		52.25%	52.90%	56.76%	54.39%	54.60%	55.73%	54.91%	55.21%	54.48%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2023Q2	2023Q1	2022Q4	2022Q3	2022Q2	2022Q1	2021Q4	2021Q3	Average
Interstate Power and Light Company	LNT	49.40%	49.41%	49.45%	49.15%	49.64%	49.69%	49.78%	45.98%	49.06%
Wisconsin Power and Light Company	LNT	45.71%	45.88%	44.97%	47.97%	44.32%	45.17%	47.14%	47.24%	46.05%
AEP Texas, Inc.	AEP	56.81%	56.45%	57.93%	58.27%	60.70%	56.72%	57.19%	58.32%	57.80%
Appalachian Power Company	AEP	52.30%	51.63%	52.24%	53.00%	50.69%	51.07%	51.66%	51.99%	51.82%
Indiana Michigan Power Company	AEP	51.78%	52.11%	50.71%	51.03%	51.66%	52.04%	52.62%	52.52%	51.81%
Kentucky Power Company	AEP	56.53%	56.06%	56.18%	56.10%	54.75%	55.11%	55.83%	56.00%	55.82%
Kingsport Power Company	AEP	50.03%	50.43%	46.11%	46.49%	50.54%	50.61%	45.82%	46.34%	48.30%
Ohio Power Company	AEP	49.86%	48.19%	49.21%	49.66%	50.14%	50.65%	51.24%	55.32%	50.53%
Public Service Company of Oklahoma	AEP	49.49%	50.00%	44.30%	44.18%	50.85%	51.34%	45.64%	45.69%	47.69%
Southwestern Electric Power Company	AEP	49.15%	49.35%	47.46%	47.25%	47.90%	48.36%	51.30%	49.45%	48.78%
Wheeling Power Company	AEP	52.96%	50.40%	50.86%	47.63%	48.60%	45.90%	45.99%	46.00%	48.54%
Duke Energy Carolinas, LLC	DUK	49.23%	48.25%	47.22%	47.68%	48.54%	49.69%	47.95%	48.36%	48.36%
Duke Energy Florida, LLC	DUK	48.24%	48.71%	49.26%	45.24%	46.11%	46.85%	47.35%	44.33%	47.01%
Duke Energy Indiana, LLC	DUK	48.44%	48.92%	47.94%	46.53%	47.30%	47.10%	46.44%	44.92%	47.20%
Duke Energy Kentucky, Inc.	DUK	46.01%	46.36%	47.03%	47.25%	47.89%	46.37%	47.10%	47.38%	46.92%
Duke Energy Ohio, Inc.	DUK	39.47%	39.81%	34.13%	34.44%	34.94%	35.21%	35.60%	36.47%	36.26%
Duke Energy Progress, LLC	DUK	50.36%	50.72%	48.73%	49.19%	48.96%	50.71%	48.24%	50.67%	49.70%
Entergy Arkansas, Inc.	ETR	53.28%	54.65%	52.05%	52.15%	52.83%	53.02%	52.16%	52.03%	52.77%
Entergy Louisiana, LLC	ETR	48.37%	48.95%	52.83%	52.96%	51.84%	59.16%	56.92%	54.98%	53.25%
Entergy Mississippi, Inc.	ETR	53.02%	54.48%	53.57%	55.03%	56.09%	54.06%	54.47%	52.47%	54.15%
Entergy New Orleans, LLC	ETR	51.71%	51.70%	52.06%	52.19%	53.17%	53.90%	54.48%	50.06%	52.41%
Entergy Texas, Inc.	ETR	48.47%	49.26%	49.64%	49.02%	46.85%	47.79%	48.29%	48.82%	48.52%
Evergy Metro	EVRG	48.12%	44.94%	47.97%	46.79%	47.38%	48.15%	48.64%	48.80%	47.60%
Evergy Kansas South	EVRG	15.05%	16.21%	16.34%	16.27%	16.66%	16.78%	16.89%	16.73%	16.37%
Evergy Missouri West, Inc.	EVRG	45.01%	45.43%	45.59%	39.16%	40.36%	47.04%	47.99%	49.63%	45.03%
Westar Energy (KPL)	EVRG	43.76%	44.21%	41.97%	41.43%	41.78%	41.19%	41.48%	41.35%	42.15%
Connecticut Light and Power Company	ES	41.91%	42.11%	41.82%	42.18%	42.47%	43.13%	43.93%	44.79%	42.79%
NSTAR Electric Company	ES	43.46%	44.39%	43.68%	48.05%	46.47%	44.32%	44.42%	45.91%	45.09%
Public Service Company of New Hampshire	ES	48.33%	50.17%	46.23%	46.96%	47.47%	50.44%	50.90%	51.09%	48.95%
Florida Power & Light Company	NEE	40.86%	38.84%	36.86%	37.30%	39.97%	41.52%	37.88%	36.65%	38.74%
Gulf Power Company	NEE							35.08%	34.73%	34.90%
Oklahoma Gas and Electric Company	OGE	46.70%	46.78%	44.35%	44.58%	45.87%	46.41%	46.62%	46.84%	46.02%
Pinnacle West Capital Corporation	PNW	51.20%	49.18%	49.75%	47.62%	48.32%	48.24%	48.88%	48.87%	49.01%
Portland General Electric Company	POR	52.21%	52.90%	56.76%	54.39%	54.60%	54.86%	54.91%	55.21%	54.48%

Notes:

[1] Ratios are weighted by actual common capital and long-term debt of Operating Subsidiaries.

[2] Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis. Analysis excludes natural gas subsidiaries.

Credit Metrics Analysis

Company Name	Ticker	Rating	Debt to Capitalization 2022	CFO pre W/C + Interest/Interest 2022	CFO pre W/C / Debt 2022	CFO pre W/C - dividends / Debt 2022
Newfoundland Power		Baa1	48.5%	4.40	17.4%	13.2%
	U.S. Electric Proxy Group [1]					
Alliant Energy Corporation	LNT	Baa2	52.0%	5.10	12.3%	7.2%
American Electric Power Company, Inc.	AEP	Baa2	55.6%	5.00	13.7%	9.7%
Duke Energy Corporation	DUK	Baa2	55.9%	4.40	11.2%	7.1%
Entergy Corporation	ETR	Baa2	59.9%	4.70	13.2%	10.2%
Evergy Inc	EVRG	Baa2	53.0%	5.80	15.2%	11.2%
Eversource Energy	ES	Baa1	52.9%	5.10	12.4%	8.6%
NextEra Energy Inc.	NEE	Baa1	53.5%	18.70	15.2%	10.0%
OGE Corp	OGE	Baa1	45.2%	8.60	27.8%	20.7%
Pinnacle West Capital Corporation	PNW	Baa1	47.9%	5.80	16.3%	11.6%
Portland General Electric Company	POR	A3	55.9%	4.70	15.1%	11.2%
U.S. Electric Proxy Group Mean		Baa1	53.2%	6.79	15.2%	10.8%
U.S. Electric Proxy Group Median			53.3%	5.10	14.4%	10.1%
	Canadian Proxy Group [1]					
Algonquin Power and Utilities Corp	AQN	NR	NR	NR	NR	NR
AltaGas Inc.	ALA	NR	NR	NR	NR	NR
Canadian Utilities Limited	CU	NR	NR	NR	NR	NR
Emera Incorporated	EMA	Baa3	58.1%	2.80	6.2%	3.2%
Hydro One, Ltd	H	A3	53.9%	4.50	14.0%	9.4%
Canadian Proxy Group		Baa2	56.0%	3.65	10.1%	6.3%

Notes & Sources:
[1] Based on Moody's adjusted credit metrics for the holding companies.
[2] Enbridge, Inc. was not included because Moody's uses different rating indicators than it does for the other companies.
[3] NR indicates that Moody's does not rate this company.

2020-2022 Average % Regulated

Utility	Ticker	% Regulated Income of All Income	% Electric of Regulated Revenues	% Electric of Regulated Income	% Electric of Regulated Assets
Alliant Energy Corporation	LNT	98%	85%	91%	86%
American Electric Power Company, Inc.	AEP	96%	100%	100%	100%
Duke Energy Corporation	DUK	100%	91%	90%	91%
Entergy Corporation	ETR	94%	98%	99%	99%
Evergy Inc	EVRG	100%	100%	100%	100%
Eversource Energy	ES	100%	85%	85%	84%
NextEra Energy Inc	NEE	79%	100%	100%	100%
OGE Corp	OGE	100%	100%	100%	100%
Pinnacle West Capital Corporation	PNW	100%	100%	100%	100%
Portland General Electric Company	POR	100%	100%	100%	100%
U.S. Proxy Group Average		**97%**	**96%**	**97%**	**96%**

Regulatory Risk Assessment

				[1]	[2]	[3]	[4]
Company	**Ticker**	**Operating Subsidiary**	**Type**	**Jurisdiction**	**Test Year**	**Rate Base Convention**	**Electric fuel/gas commodity/purch. power**
US Electric							
Alliant Energy Corporation	LNT	Interstate Power & Light Co.	Electric	Iowa	Fully Forecasted	Average	✓
	LNT	Interstate Power & Light Co.	Natural Gas	Iowa	Fully Forecasted	Average	✓
	LNT	Wisconsin Power & Light Co.	Electric	Wisconsin	Fully Forecasted	Average	✓
	LNT	Wisconsin Power & Light Co.	Natural Gas	Wisconsin	Fully Forecasted	Average	✓
American Electric Power Company, Inc.	AEP	Southwestern Electric Power Co.	Electric	Arkansas	Historic	Year-end	✓
	AEP	Indiana Michigan Power Co.	Electric	Indiana	Fully Forecasted	Year-end	✓
	AEP	Kentucky Power Co.	Electric	Kentucky	Historic	Year-end	✓
	AEP	Ohio Power Co.	Electric	Ohio	Partially-Forecasted	Date-certain	
	AEP	Southwestern Electric Power Co.	Electric	Louisiana PSC	Historic	Average	✓
	AEP	Public Service Co. of Oklahoma	Electric	Oklahoma	Historic	Year-end	✓
	AEP	Kingsport Power Co.	Electric	Tennessee	Fully Forecasted	Average	✓
	AEP	Indiana Michigan Power Co.	Electric	Michigan	Fully Forecasted	Average	✓
	AEP	AEP Texas	Electric	Texas PUC	Historic	Year-end	
	AEP	Electric Transmission Texas LLC	Electric	Texas PUC	Historic	Year-end	
	AEP	Southwestern Electric Power Co.	Electric	Texas PUC	Historic	Year-end	✓
	AEP	Appalachian Power Co.	Electric	Virginia	Historic	Average	✓
	AEP	Appalachian Power Co./Wheeling Power (	Electric	West Virginia	Historic	Average	✓
Duke Energy Corporation	DUK	Duke Energy Florida	Electric	Florida	Fully Forecasted	Average	✓
	DUK	Duke Energy Indiana LLC	Electric	Indiana	Fully Forecasted	Year-end	✓
	DUK	Duke Energy Kentucky Inc.	Electric	Kentucky	Fully Forecasted	Average	✓
	DUK	Duke Energy Kentucky Inc.	Natural Gas	Kentucky	Fully Forecasted	Average	✓
	DUK	Duke Energy Carolinas LLC	Electric	North Carolina	Historic	Year-end	✓
	DUK	Duke Energy Progress LLC	Electric	North Carolina	Historic	Year-end	✓
	DUK	Piedmont Natural Gas Co. Inc	Gas	North Carolina	Historic	Year-end	✓
	DUK	Duke Energy Ohio Inc.	Electric	Ohio	Partially-Forecasted	Date-certain	
	DUK	Duke Energy Ohio Inc.	Gas	Ohio	Partially-Forecasted	Date-certain	✓
	DUK	Duke Energy Carolinas LLC	Electric	South Carolina	Historic	Year-end	✓
	DUK	Duke Energy Progress LLC	Electric	South Carolina	Historic	Year-end	✓
	DUK	Piedmont Natural Gas Co. Inc	Gas	South Carolina	Historic	Year-end	✓
	DUK	Piedmont Natural Gas Co. Inc	Gas	Tennessee	Fully Forecasted	Average	✓

Regulatory Risk Assessment

Company	Ticker	Operating Subsidiary	Type	Jurisdiction	Test Year	Rate Base Convention	Electric fuel/gas commodity/purch. power
				[1]	[2]	[3]	[4]
Entergy Corporation	ETR	Entergy Arkansas LLC	Electric	Arkansas	Fully Forecasted	Average	✓
	ETR	Entergy New Orleans LLC	Electric	Louisiana-NOCC	Partially-Forecasted	Year-end	✓
	ETR	Entergy New Orleans LLC	Gas	Louisiana-NOCC	Partially-Forecasted	Year-end	✓
	ETR	Entergy Louisiana LLC	Electric	Louisiana PSC	Historic	Average	✓
	ETR	Entergy Louisiana LLC	Gas	Louisiana PSC	Historic	Year-end	✓
	ETR	Entergy Mississippi LLC	Electric	Mississippi	Fully Forecasted	Average	✓
	ETR	Entergy Texas Inc.	Electric	Texas PUC	Historic	Year-end	✓
Evergy Inc	EVRG	Evergy Kansas Central Inc.	Electric	Kansas	Historic	Year-end	✓
	EVRG	Evergy Kansas South Inc.	Electric	Kansas	Historic	Year-end	✓
	EVRG	Evergy Metro Inc.	Gas	Kansas	Historic	Year-end	✓
	EVRG	Evergy Metro Inc.	Electric	Missouri	Historic	Year-end	✓
	EVRG	Evergy Missouri West Inc.	Electric	Missouri	Historic	Year-end	✓
Eversource Energy	ES	Connecticut Light and Power Co.	Electric	Connecticut	Historic	Year-end	
	ES	Yankee Gas Services Co.	Gas	Connecticut	Historic	Year-end	✓
	ES	Eversource Gas Co. of Massachusetts	Gas	Massachusetts	Historic	Year-end	✓
	ES	NSTAR Electric Co.	Electric	Massachusetts	Historic	Year-end	
	ES	NSTAR Gas Co.	Gas	Massachusetts	Historic	Year-end	✓
	ES	Public Service Co. of New Hampshire	Electric	New Hampshire	Historic	Year-end	✓
NexEra Energy Inc	NEE	Florida Power & Light Co.	Electric	Florida	Fully Forecasted	Average	✓
	NEE	Pivotal Utility Holdings Inc.	Gas	Florida	Fully Forecasted	Average	✓
	NEE	Lone Star Transmission LLC	Electric	Texas	Historic	Year-end	
OGE Energy Corp.	OGE	Oklahma Gas & Electric Co.	Electric	Oklahoma	Historic	Year-end	✓
Pinnacle West Capital Corporation	PNW	Arizona Public Service Co.	Electric	Arizona	Historic	Year-end	✓
Portland General Electric Company	POR	Portland General Electric Co.	Electric	Oregon	Fully Forecasted	Average	✓
Proxy Group Results				Total 54	Fully Forecasted = 31% Partially-Forecasted = 9% Historic = 59%	Year-end = 59% Average = 35% Date-certain = 6%	Adjustment Clauses Count c 47 87%
Newfoundland Power			Electric	NL	Fully Forecasted		✓

Regulatory Risk Assessment

Company	Ticker	Operating Subsidiary	Type	[5] Conserv. program expense	[6] Full Decoupling	Partial Decoupling	[7] Renewables expense	[8] Environmental compliance	[9] Generation capacity
US Electric									
Alliant Energy Corporation	LNT	Interstate Power & Light Co.	Electric	✓			✓	✓	
	LNT	Interstate Power & Light Co.	Natural Gas	✓					
	LNT	Wisconsin Power & Light Co.	Electric						
	LNT	Wisconsin Power & Light Co.	Natural Gas						
American Electric Power Company, Inc.	AEP	Southwestern Electric Power Co.	Electric	✓		✓		✓	✓
	AEP	Indiana Michigan Power Co.	Electric	✓		✓	✓	✓	
	AEP	Kentucky Power Co.	Electric	✓		✓		✓	
	AEP	Ohio Power Co.	Electric	✓		✓	✓		
	AEP	Southwestern Electric Power Co.	Electric	✓		✓			
	AEP	Public Service Co. of Oklahoma	Electric	✓		✓	✓		
	AEP	Kingsport Power Co.	Electric						
	AEP	Indiana Michigan Power Co.	Electric	✓	✓		✓		
	AEP	AEP Texas	Electric	✓					
	AEP	Electric Transmission Texas LLC	Electric						
	AEP	Southwestern Electric Power Co.	Electric	✓					
	AEP	Appalachian Power Co.	Electric	✓				✓	✓
	AEP	Appalachian Power Co./Wheeling Power (	Electric	✓				✓	
Duke Energy Corporation	DUK	Duke Energy Florida	Electric	✓			✓	✓	✓
	DUK	Duke Energy Indiana LLC	Electric	✓		✓	✓	✓	
	DUK	Duke Energy Kentucky Inc.	Electric	✓		✓		✓	
	DUK	Duke Energy Kentucky Inc.	Natural Gas	✓		✓			
	DUK	Duke Energy Carolinas LLC	Electric	✓			✓	✓	
	DUK	Duke Energy Progress LLC	Electric	✓			✓	✓	
	DUK	Piedmont Natural Gas Co. Inc	Gas	✓	✓				
	DUK	Duke Energy Ohio Inc.	Electric	✓		✓	✓		
	DUK	Duke Energy Ohio Inc.	Gas					✓	
	DUK	Duke Energy Carolinas LLC	Electric	✓				✓	
	DUK	Duke Energy Progress LLC	Electric	✓				✓	
	DUK	Piedmont Natural Gas Co. Inc	Gas	✓		✓			
	DUK	Piedmont Natural Gas Co. Inc	Gas			✓			

Regulatory Risk Assessment

				[5]	[6]		[7]	[8]	[9]
Company	**Ticker**	**Operating Subsidiary**	**Type**	**Conserv. program expense**	**Full Decoupling**	**Partial Decoupling**	**Renewables expense**	**Environmental compliance**	**Generation capacity**
Entergy Corporation	ETR	Entergy Arkansas LLC	Electric	✓		✓	✓		✓
	ETR	Entergy New Orleans LLC	Electric	✓			✓	✓	
	ETR	Entergy New Orleans LLC	Gas						
	ETR	Entergy Louisiana LLC	Electric	✓		✓			
	ETR	Entergy Louisiana LLC	Gas						
	ETR	Entergy Mississippi LLC	Electric			✓			
	ETR	Entergy Texas Inc.	Electric	✓					✓
Evergy Inc	EVRG	Evergy Kansas Central Inc.	Electric	✓		✓	✓	✓	
	EVRG	Evergy Kansas South Inc.	Electric	✓		✓	✓	✓	
	EVRG	Evergy Metro Inc.	Gas	✓					
	EVRG	Evergy Metro Inc.	Electric	✓		✓			
	EVRG	Evergy Missouri West Inc.	Electric	✓		✓	✓		
Eversource Energy	ES	Connecticut Light and Power Co.	Electric	✓	✓				
	ES	Yankee Gas Services Co.	Gas	✓	✓				
	ES	Eversource Gas Co. of Massachusetts	Gas	✓	✓			✓	
	ES	NSTAR Electric Co.	Electric	✓	✓		✓		
	ES	NSTAR Gas Co.	Gas	✓	✓				✓
	ES	Public Service Co. of New Hampshire	Electric			✓			
NexEra Energy Inc	NEE	Florida Power & Light Co.	Electric	✓			✓	✓	✓
	NEE	Pivotal Utility Holdings Inc.	Gas	✓				✓	
	NEE	Lone Star Transmission LLC	Electric						
OGE Energy Corp.	OGE	Oklahma Gas & Electric Co.	Electric	✓		✓		✓	
Pinnacle West Capital Corporation	PNW	Arizona Public Service Co.	Electric	✓		✓	✓	✓	
Portland General Electric Company	POR	Portland General Electric Co.	Electric	✓			✓	✓	✓
Proxy Group Results				ınd Percentage of total proxy group					
				43	7	22	19	23	8
				80%	13%	41%	35%	43%	15%
Newfoundland Power			Electric	✓	✓				

Regulatory Risk Assessment

Company	Ticker	Operating Subsidiary	Type	[10] Generic infrastructure	[11] Transmission expense	[12] AFUDC/CWIP	[13] UBS Ranking of Reg Environment	[14] Storm Cost Recovery
US Electric								
Alliant Energy Corporation	LNT	Interstate Power & Light Co.	Electric		✓	Pre-approval	2	
	LNT	Interstate Power & Light Co.	Natural Gas			Pre-approval	2	
	LNT	Wisconsin Power & Light Co.	Electric			No. CWIP may be allowed on case-by-case basis	1	
	LNT	Wisconsin Power & Light Co.	Natural Gas			No. CWIP may be allowed on case-by-case basis	1	
American Electric Power Company, Inc.	AEP	Southwestern Electric Power Co.	Electric		✓	No	2	
	AEP	Indiana Michigan Power Co.	Electric	✓	✓	CWIP for pollution-control equipment	1	
	AEP	Kentucky Power Co.	Electric			CWIP	2	
	AEP	Ohio Power Co.	Electric	✓	✓	CWIP if project is 75% complete	3	✓
	AEP	Southwestern Electric Power Co.	Electric			CWIP allowed in some cases	2	
	AEP	Public Service Co. of Oklahoma	Electric	✓	✓	Pre-approval and CWIP for environmental compliance and transmission projects	3	
	AEP	Kingsport Power Co.	Electric			CWIP	3	
	AEP	Indiana Michigan Power Co.	Electric			CWIP for pollution-control equipment	1	
	AEP	AEP Texas	Electric	✓	✓	Surcharge mechanism for new investments. CWIP allowed for certain enviromental compliance cost	3	
	AEP	Electric Transmission Texas LLC	Electric	✓	✓	Surcharge mechanism for new investments. CWIP allowed for certain enviromental compliance cost	3	
	AEP	Southwestern Electric Power Co.	Electric	✓	✓	Surcharge mechanism for new investments. CWIP allowed for certain enviromental compliance cost	3	
	AEP	Appalachian Power Co.	Electric		✓	CWIP allowed in generation riders	3	
	AEP	Appalachian Power Co./Wheeling Power (	Electric			CWIP for large generation and transmission projects	3	
Duke Energy Corporation	DUK	Duke Energy Florida	Electric			CWIP for nuclear, IGCC, or upgrades to existing facilities	1	✓
	DUK	Duke Energy Indiana LLC	Electric	✓	✓	CWIP for pollution-control equipment	1	✓
	DUK	Duke Energy Kentucky Inc.	Electric			CWIP	2	✓
	DUK	Duke Energy Kentucky Inc.	Natural Gas	✓		CWIP	2	
	DUK	Duke Energy Carolinas LLC	Electric			CWIP and pre-approval for baseload gen. facilities	1	✓
	DUK	Duke Energy Progress LLC	Electric			CWIP and pre-approval for baseload gen. facilities	1	✓
	DUK	Piedmont Natural Gas Co. Inc	Gas	✓		CWIP and pre-approval for baseload gen. facilities	1	
	DUK	Duke Energy Ohio Inc.	Electric	✓	✓	CWIP if project is 75% complete	3	✓
	DUK	Duke Energy Ohio Inc.	Gas	✓		CWIP if project is 75% complete	3	
	DUK	Duke Energy Carolinas LLC	Electric			CWIP	3	✓
	DUK	Duke Energy Progress LLC	Electric			CWIP	3	✓
	DUK	Piedmont Natural Gas Co. Inc	Gas			CWIP	3	
	DUK	Piedmont Natural Gas Co. Inc	Gas	✓		CWIP	3	

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Company	Ticker	Operating Subsidiary	Type	[10] Generic infrastructure	[11] Transmission expense	[12] AFUDC/CWIP	[13] UBS Ranking of Reg Environment	[14] Storm Cost Recovery
Entergy Corporation	ETR	Entergy Arkansas LLC	Electric	✓	✓	No	2	✓
	ETR	Entergy New Orleans LLC	Electric		✓	CWIP allowed in some cases	2	✓
	ETR	Entergy New Orleans LLC	Gas			CWIP allowed in some cases	2	✓
	ETR	Entergy Louisiana LLC	Electric	✓		CWIP allowed in some cases	2	✓
	ETR	Entergy Louisiana LLC	Gas	✓		CWIP allowed in some cases	2	
	ETR	Entergy Mississippi LLC	Electric		✓	CWIP for environmental investments and non baseload items	4	✓
	ETR	Entergy Texas Inc.	Electric	✓	✓	Surcharge mechanism for new investments. CWIP allowed for certain enviromental compliance cost	3	✓
Evergy Inc	EVRG	Evergy Kansas Central Inc.	Electric		✓	CWIP for plant-related work completed within one year	4	
	EVRG	Evergy Kansas South Inc.	Electric		✓	CWIP for plant-related work completed within one year	4	
	EVRG	Evergy Metro Inc.	Gas	✓	✓	CWIP for plant-related work completed within one year	4	
	EVRG	Evergy Metro Inc.	Electric	✓	✓	No	3	
	EVRG	Evergy Missouri West Inc.	Electric	✓	✓	No	3	
Eversource Energy	ES	Connecticut Light and Power Co.	Electric	✓	✓	No	4	✓
	ES	Yankee Gas Services Co.	Gas	✓		No	4	
	ES	Eversource Gas Co. of Massachusetts	Gas	✓		No	3	
	ES	NSTAR Electric Co.	Electric	✓	✓	No	3	✓
	ES	NSTAR Gas Co.	Gas	✓		No	3	
	ES	Public Service Co. of New Hampshire	Electric	✓	✓	No	4	✓
NexEra Energy Inc	NEE	Florida Power & Light Co.	Electric			CWIP for new nuclear, IGCC plant, transmission lines, increased capacity	1	✓
	NEE	Pivotal Utility Holdings Inc.	Gas	✓		CWIP for new nuclear, IGCC plant, transmission lines, increased capacity	1	
	NEE	Lone Star Transmission LLC	Electric	✓	✓	Certain environmental compliance costs	3	
OGE Energy Corp.	OGE	Oklahma Gas & Electric Co.	Electric	✓	✓	Investment placed in service within six months of end of test period. State statutes allow CWIP treatment for certain environmental costs.	3	✓
Pinnacle West Capital Corporation	PNW	Arizona Public Service Co.	Electric		✓	No	5	
Portland General Electric Company	POR	Portland General Electric Co.	Electric		✓	CWIP prohibited by law	3	
Proxy Group Results				28 52%	27 50%		2.5	20 37%
Newfoundland Power			Electric				3.0	

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				[1]	[2]	[3]	[4]
Company	**Ticker**	**Operating Subsidiary**	**Type**	**Jurisdiction**	**Test Year**	**Rate Base Convention**	**Electric fuel/gas commodity/purch. power**

Notes

[1] Source: "Adjustment Clauses: A State-by-state Overview," Regulatory Research Associates, July 18, 2022 and S&P Capital IQ. Reviewed regulatory filings and orders, annual reports, annual information forms, when not covered by S&P
[2] Source: " Rate Case History (Past Rate Cases)". S&P Capital IQ
[3] Source: " Rate Case History (Past Rate Cases)". S&P Capital IQ
[4] - [11] Source: "Adjustment Clauses: A State-by-state Overview," Regulatory Research Associates, July 18, 2022 and S&P Capital IQ. Reviewed regulatory filings and orders, annual reports, annual information forms, when not covered by SNL
[12] Source: Commission's profile on S&P Capital IQ
[13] Source: "North America Power & Utilities. Mind the Gap(s): 2021 Utility Outlook". UBS December 14, 2020
[14] Source: SEC Form 10-K for each holding company; Commission profiles on S&P Capital IQ