WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

May 28, 2024

Board of Commissioners
of Public Utilities
P.O. Box 21040
120 Torbay Road
St. John's, NL A1A 5B2

Attention: Jo-Anne Galarneau
Executive Director and Board Secretary

Dear Ms. Galarneau:

Re: Newfoundland Power's 2025/2026 General Rate Application – Rebuttal Evidence

Please find enclosed the original and nine copies of Newfoundland Power's:

(i) Newfoundland Power Inc. Rebuttal Evidence in response to the Expert Reports of The Brattle Group and C. Douglas Bowman; and

(ii) Cost of Capital Rebuttal Testimony prepared by James M. Coyne and John P. Trogonoski of Concentric Energy Advisors Inc.

If you have any questions regarding the enclosed, please feel free to contact the undersigned.

Yours truly,

Lindsay Hollett

Lindsay Hollett
Senior Legal Counsel &
Assistant Corporate Secretary

Enclosures

c. Shirley Walsh
Newfoundland and Labrador Hydro

Donald Murphy
International Brotherhood of Electrical
Workers, Local 1620

Dennis Browne, K.C.
Browne Fitzgerald Morgan & Avis

Newfoundland Power Inc.
55 Kenmount Road • P.O. Box 8910 • St. John's, NL A1B 3P6
PHONE (709) 737-5364 • FAX (709) 737-2974 • **lhollett@newfoundlandpower.com**

Newfoundland Power
2025/2026 General Rate Application:
Rebuttal Evidence

May 28, 2024

TABLE OF CONTENTS

Page

SECTION 1: INTRODUCTION

On April 17, 2024, the Board of Commissioners of Public Utilities (the "Board") filed an expert report prepared by The Brattle Group ("Brattle") on Newfoundland Power's Load Forecasting Methodology (the "Brattle Load Forecasting Report").[1] On the same date, the Consumer Advocate filed *Pre-Filed Evidence of C. Douglas Bowman* in respect of various matters (the "Bowman Evidence") in Newfoundland Power's *2025/2026 General Rate Application* (the "2025/2026 GRA").[2] On April 24, 2024, the Board filed an expert report prepared by Brattle on Newfoundland Power's Deferral Accounts (the "Brattle Deferral Account Report").[3]

This Company Rebuttal Evidence is presented in response to the Brattle Load Forecasting Report, the Bowman Evidence and the Brattle Deferral Account Report (collectively, the "Expert Reports").

The purpose of this Rebuttal Evidence is to provide the Company's views on the recommendations outlined in the Expert Reports. This includes providing information to assist the Board in considering the recommendations of the experts, and more specifically for the Bowman Evidence, clarifying the circumstances and information underpinning the recommendations.

---

[1] See Brattle, *Review of Newfoundland Power Load Forecasting Methodology*, prepared by Sanem Sergici, Sai Shetty and Philip Hanser, April 17, 2024.
[2] See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024.
[3] See Brattle, *Review of Newfoundland Power's Deferral Accounts*, prepared by Philip Q. Hanser and Adam Wyonzek, April 24, 2024.

SECTION 2: LOAD FORECASTING METHODOLOGY

2.1 BRATTLE LOAD FORECASTING REVIEW

Brattle reviewed Newfoundland Power's energy and peak demand forecasting methodology as detailed in the Company's 2025/2026 GRA and responses to requests for information. Brattle determined that the Company's energy and peak demand forecasts provide reasonable accuracy for the 2025/2026 GRA.[4]

Brattle also provided potential improvements and considerations for total energy sales and peak demand forecasts to be used in future general rate cases.[5] This included a recommendation for Newfoundland Power to submit a more detailed forecasting methodology report in future general rate applications.[6] It also included suggestions that may further improve the accuracy of the Company's energy and demand forecasts.

2.2 FORECAST REPORT

The *Customer, Energy and Demand Forecast* report provided as part of the 2025/2026 GRA has been Newfoundland Power's standard approach to detailing the Company's forecast in general rate proceedings.[7] The Company has been providing the report in its current form as part of its general rate applications since 2007.[8]

---

[4] See Brattle, *Review of Newfoundland Power Load Forecasting Methodology*, prepared by Sanem Sergici, Sai Shetty and Philip Hanser, April 17, 2024, pages 16 and 23.

[5] Ibid., pages 24 and 25.

[6] See potential improvement and consideration #1 on page 24 of Brattle's *Review of Newfoundland Power Load Forecasting Methodology,* prepared by Sangem Sergici, Sai Shetty and Philip Hanser, April 17, 2024.

[7] See the 2025/2026 GRA, *Volume 2: Supporting Materials, Customer, Energy and Demand Forecast*.

[8] See Newfoundland Power's *2008 General Rate Application, Volume 2: Supporting Materials, Customer, Energy and Demand Forecast*.

In addition to the *Customer, Energy and Demand Forecast* report provided in support of the 2025/2026 GRA, additional evidence was provided in the form of responses to requests for information.[9] The responses to the requests for information provided additional details with respect to methodologies and assumptions used in the forecast.

Newfoundland Power recognizes that a more detailed report in relation to its *Customer, Energy and Demand Forecast* would provide the Board additional clarity in assessing its forecast and forecasting methodology. The Company is supportive of the Brattle recommendation to include a detailed forecasting methodology report in its future general rate applications.

2.3 POTENTIAL IMPROVEMENTS AND CONSIDERATIONS

Brattle observes that Newfoundland Power's energy and demand forecasts are simplistic.[10] Brattle offers several suggestions that may improve the results of the Company's forecasting accuracy. Without a comprehensive review of the forecast, including direct engagement between the Company and an expert, it is unclear if all of Brattle's suggestions would improve the overall accuracy of the Company's energy and demand forecast.

To further evaluate Brattle's suggestions, the Company plans to engage an expert to review the Company's forecasting methodology. The review will consider potential improvements to the

[9] See for example, the responses to Requests for Information PUB-NP-086, PUB-NP-087, PUB-NP-088, PUB-NP-089, PUB-NP-090, PUB-NP-091, PUB-NP-092, PUB-NP-093, PUB-NP-094, PUB-NP-095, PUB-NP-096, PUB-NP-097, PUB-NP-098, PUB-NP-101, PUB-NP-102, PUB-NP-103, PUB-NP-139, PUB-NP-154, PUB-NP-155, PUB-NP-156, PUB-NP-157, PUB-NP-158, PUB-NP-159, PUB-NP-166, CA-NP-141, CA-NP-143, CA-NP-144, CA-NP-145, NLH-NP-083 and NLH-NP-131.

[10] See Brattle, *Review of Newfoundland Power Load Forecasting Methodology*, prepared by Sanem Sergici, Sai Shetty and Philip Hanser, April 17, 2024, pages 19 and 23.

methodology, including the recommendations of the Brattle Load Forecasting Report. The results of the review will be provided to the Board.

SECTION 3: DEFERRAL ACCOUNTS

3.1 OVERVIEW

In the Brattle Deferral Account Report, Brattle provides four recommendations for the Board to consider in its order on the Company's 2025/2026 GRA. Three of the recommendations relate to Newfoundland Power's supply cost mechanisms and one relates to its excess earnings account.

The following provides Newfoundland Power's rebuttal to Brattle's recommendations. The purpose of the rebuttal is to provide the Company's views on the recommendations. This includes providing context surrounding Newfoundland Power's deferral accounts, as well as other information to assist the Board in considering Brattle's recommendations.

3.2 CONTEXT

Newfoundland Power's supply cost mechanisms provide recovery of variances in supply costs that are largely out of the Company's control. The Energy Supply Cost Variance ("ESCV") and Demand Management Incentive ("DMI") accounts capture variances in unit energy and demand costs from those reflected in test year revenue requirements. The Weather Normalization Reserve ("WNR") normalizes the effects of weather and hydrology on the Company's sales and purchased power expense. As provided by both the Company's and Brattle's jurisdictional reviews, mechanisms that permit full recovery of supply costs by investor-owned distribution utilities are commonplace in Canadian regulatory practice.[11]

[11] See the response to Request for Information PUB-NP-071 and Brattle, *Review of Newfoundland Power Load Forecasting Methodology*, prepared by Sanem Sergici, Sai Shetty and Philip Hanser, April 17, 2024, page 13.

The Company's supply cost mechanisms are longstanding and have not been controversial. The ESCV and DMI accounts were first approved by the Board in Order No. P.U. 32 (2007). The hydrology component of the WNR was approved in Order No. P.U. 32 (1968) and the degree day component was approved in Order No. P.U. 1 (1974).

Larger fluctuations in supply costs have occurred since 2020, following implementation of the current wholesale rate in October 2019, which has a second block energy rate of 18.165¢ per kWh.[12] The second block energy rate is used to determine both the ESCV account and the WNR. The volatility in these accounts is expected to decrease following implementation of a revised wholesale rate for Newfoundland Power, which is expected to include a second block rate based on energy exports.[13] A new wholesale rate may be implemented as early as January 1, 2025.[14]

Rate-setting approaches for investor-owned utilities vary throughout Canada. For Newfoundland Power, Nova Scotia Power and Maritime Electric, electricity rates are set using a traditional cost of service ("COS") model. For the Ontario and Alberta utilities, a performance-based regulation ("PBR") approach is used.[15] In British Columbia, FortisBC Inc.'s ("FortisBC") Multi-Year Rate Plan ("MRP") is a hybrid model that contains elements of both PBR and COS.[16] Varying approaches to rate-setting reflect the unique circumstances of each jurisdiction and its respective

---

[12] See, for example, the response to Request for Information PUB-NP-071, Attachment A, page 6, tables 3 and 4.

[13] See the 2025/2026 GRA, *Volume 1: Application, Company Evidence and Exhibits, 4.3.4 Deductions from Revenue Requirement,* page 4-9, table 4-10.

[14] See the response to Request for Information PUB-NP-132.

[15] Under PBR, a formula is used to set electricity rates for a specified term, typically five years, based on rates originally set using COS principles.

[16] See the British Columbia Utilities Commission ("BCUC")'s *Decision and Orders G-165-20 and G-166-20*, June 22, 2020, page 170. The BCUC states that FortisBC's MRPs *"are not a true or traditional form of performance-based incentive plans. Instead, they are a hybrid and somewhat unique model, as they contain elements more commonly found in COS ratemaking regimes, such as the use of forecasts instead of formulas."*

utilities. Regulatory accounts used by utilities are done so within the context of the rate-setting approach. Regardless of the approach used, it is a standard goal of both regulators and investor-owned utilities in Canada to deliver safe and reliable power to customers in an efficient manner.

3.3 SUPPLY COST MECHANISMS

ESCV Account

Brattle recommends that the Board should redefine the ESCV account to include revenue variances associated with energy supply. To support this recommendation, Brattle provides that a similar practice is followed by FortisBC.[17]

FortisBC's electricity rates are set using a MRP approach for the five-year period 2020 to 2024.[18] Under this approach, FortisBC's revenue deficiency for the upcoming year is recovered through an annual customer rate change.[19] The MRP allows for annual recovery of all changes in FortisBC's revenue requirement, such as sales, depreciation, operating expenses and return on rate base.[20] The recovery of the annual changes in utility costs are approved by the BCUC outside of a typical GRA process used in a traditional COS model. As such, while FortisBC has a mechanism to flow-through variances in revenues related to power supply, it is within a rate-setting framework that is materially different than that used for Newfoundland Power. Further, it does not appear that the practice followed by FortisBC for the flow-through of variances in revenues related to power supply is used for other investor-owned utilities in Canada.

---

[17] See Brattle, *Review on Newfoundland Power's Deferral Accounts,* prepared by Philip Q. Hanser and Adam Wyonzek, April 24, 2024, pages 13 and 14.

[18] See the BCUC's *Decision and Orders G-165-20 and G-166-20*, June 22, 2020, Order Number G-166-20.

[19] See, for example, page 7 of FortisBC's *Multi-Year Rate Plan for 2020 through 2024, Annual Review for 2024 Rates,* August 4, 2023.

[20] Ibid. As outlined on page 8, FortisBC establishes the majority of its operating and maintenance expense by a formula approved by the BCUC during the MRP term.

Based on the context provided above, the Company submits that it would not be appropriate to adopt one component of FortisBC's MRP rate making framework for Newfoundland Power.

DMI Account

Brattle also recommends that the DMI account should be modified to remove the incentive threshold related to peak demand. The account would still exist to capture variances from actual to test year demand costs. To support this recommendation, Brattle provides that incentives related specifically to demand cost management are not common amongst investor-owned Canadian electric utilities, and recognizes that Newfoundland Power has limited ability manage its demand costs.[21]

Brattle's findings are consistent with the Company's evidence in support of its proposal to reduce the incentive amount to a set amount of ±$500,000.[22] In Newfoundland Power's view, both alternatives (the Company's proposed ±$500,000 threshold, or no threshold, as recommended by Brattle) are reasonable.

With respect to managing demand costs, as outlined in the response to Request for Information PUB-NP-074, while short-term reductions in demand costs from those determined in the test year are limited, the Company continues to focus on managing its demand costs to reduce overall costs for customers. This includes the continued implementation of its conservation and demand management initiatives, which are forecast to achieve peak demand savings of 68 MW by 2025.

[21] See Brattle, *Review on Newfoundland Power's Deferral Accounts,* prepared by Philip Q. Hanser and Adam Wyonzek, April 24, 2024, page 14.

[22] See the 2025/2026 GRA, *Volume 1: Application, Company Evidence and Exhibits, 3.4.2 Demand Management Incentive,* page 3-50.

WNR

Finally, Brattle recommends that the Board require Newfoundland Power to file a report as part of its next GRA providing a detailed explanation of its WNR methodology for both the Degree Days Normalization ("Degree Day") and Hydrology Production Equalization ("Hydrology") components. In support of its recommendations, Brattle provides the review is warranted given the time since its last review, the unique structure of Newfoundland Power's WNR compared to other investor-owned Canadian electric utilities, and the statement that it is not evident to Brattle that the Hydrology component should be included in the WNR.

Newfoundland Power serves a substantial heating load.[23] Variations in weather, therefore, can have a substantial effect on the Company's purchased power expense. The longevity in Newfoundland Power's WNR, which has been in effect for approximately 50 years, reflects this fundamental fact.[24] As such, the time since the last review of the WNR does not create a need to review the WNR at this time.

The Company purchases approximately 93% of its power supply requirements from Newfoundland and Labrador Hydro ("Hydro"). This single supply dependence is relatively rare for investor-owned electric utilities in Canada.[25] The Company is subject to the wholesale rate charged by Hydro, which currently includes a second block rate of 18.165¢ per kWh. Variances in power supply requirements, which occur in part due to changes in weather and water inflows, are costed at the second block rate. That rate is significantly higher than the average energy

[23] Approximately 74% of Newfoundland Power's residential customers rely on electricity as their primary heating source.

[24] The Company's WNR, through the Degree Day and Hydrology components, normalizes the effects of weather and hydrology on its sales and purchased power expense.

[25] See the 2025/2026 GRA, *Volume 2: Supporting Materials, Cost of Capital: Mr. James Coyne, Concentric Energy Advisors, Inc,* pages 71-72.

supply cost of 6.940¢ per kWh underpinning current customer rates. Without both the Degree Day and the Hydrology components of the WNR, Newfoundland Power would not be permitted full recovery of its supply costs, which would not be consistent with generally accepted sound Canadian regulatory practice.

Rate-setting and related regulatory mechanisms vary across Canada for investor-owned utilities. With respect to the Degree Day component of the WNR, Maritime Electric has a similar weather normalization clause that protects against changes in volume/demand due to abnormal weather. FortisBC operates under a revenue stabilization plan that includes full protection against volumetric risk, which would inherently include the effects of weather.[26] While Nova Scotia Power does not have a weather normalization mechanism, it does have a storm cost recovery rider for extraordinary storm costs beyond specified levels.[27] Concentric provides the following with respect to the Company's WNR and its comparison to other 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."*[28]

The Hydrology component of the WNR is necessary to permit Newfoundland Power to recover its variances in purchased power costs due to changes in water inflows. Maritime Electric's Energy Cost Adjustment Mechanism ("ECAM") allows the Company to recover the actual cost

26 See the 2025/2026 GRA, *Volume 2: Supporting Materials, Cost of Capital: Mr. James Coyne, Concentric Energy Advisors, Inc.,* pages 74 and 75.
27 Ibid., page 77.
28 Ibid., page 75.

of fuel and purchased power compared to the forecasted amount.[29] Nova Scotia Power utilizes a Fuel Adjustment Mechanism ("FAM") to account for variances in its test year power supply costs.[30] FortisBC has an annual fuel and purchased power cost recovery mechanism.[31] These mechanisms allow for the recovery of the utility's supply costs, which come from a variety of sources.[32] As such, a separate reserve similar to Newfoundland Power's Hydrology component is not required for those utilities.

Newfoundland Power does not have an overarching supply cost mechanism that captures all variances in supply costs, comparable to those described in Prince Edward Island, British Columbia, or Nova Scotia. Instead, its ESCV account, DMI account and Hydrology component of the WNR work together to ensure the same result is achieved – to permit recovery of its power supply costs. In the Company's view, a suggestion to review, change, or eliminate one component of its framework of supply cost mechanisms, based on a limited view of its comparability to other utilities, is not appropriate.

Brattle also suggests it would be beneficial for the Board to separate the two calculations included in the WNR for the potential to create incentives for Newfoundland Power to maintain efficient and low-cost hydroelectric facilities.[33]

---

29 See Maritime Electric's *2023 to 2025 General Rate Application*, June 20, 2022, Appendix F, page 66.
30 See Brattle, *Review on Newfoundland Power's Deferral Accounts,* prepared by Philip Q. Hanser and Adam Wyonzek, April 24, 2024, page 11
31 See the 2025/2026 GRA, *Volume 2: Supporting Materials, Cost of Capital: Mr. James Coyne, Concentric Energy Advisors, Inc.,* page 71.
32 See, for example, the response to Request for Information NP-PUB-005.
33 See Brattle, *Review on Newfoundland Power's Deferral Accounts,* prepared by Philip Q. Hanser and Adam Wyonzek, April 24, 2024, page 15.

Newfoundland Power operates 23 hydro production facilities ("hydro plants") within its service territory. The hydro plants have a combined maximum rated capacity of 97.5 MW and annual production of approximately 439 GWh. The Company has a legislative obligation to operate its generation facilities in the most efficient manner.[34] Newfoundland Power's plant availability has averaged 95% over the last decade.

The operation of the Company's hydro plants is coordinated with Hydro to ensure the economic dispatch of generation on the Island Interconnected System. To meet system reserve requirements, Hydro dispatches Newfoundland Power's hydro plants in accordance with its BA-P-012 (T-001) Operating Reserves procedure.[35] The procedure outlines 12 sequential steps to be taken to ensure adequate capacity is available to meet system reserve requirements. Maximizing Newfoundland Power's hydro generation is the second step of Hydro's 12-step resource dispatching sequence. This confirms the role of the Company's hydro plants as an economic source of energy and generating capacity.

Newfoundland Power completes upgrades to increase the output of its plants where possible. This typically occurs during the refurbishment of hydro plants, which are subject to Board approval. Further, Newfoundland Power completes any refurbishment of its plants after the spring run-off to minimize the amount of spill associated with completing the planned work. In addition, the Company maintains and refurbishes its hydro plants to reduce the risk of unplanned work which can lead to spills.

---

34 See section 3(b)(i) of the *Electrical Power Control Act, 1994.*

35 The BA-P-012 (T-001) Operating Reserves procedure outlines the requirements to assess and maintain sufficient operating reserve to meet current and anticipated customer needs under normal operating conditions and for specific contingency situations that result in reductions in resources. The procedure was most recently filed as PUB-NLH-002, Attachment 1 as a part of Hydro's *Reliability and Resource Adequacy Study* review.

Finally, Newfoundland Power has a ±$750,631 cost threshold associated with its power supply costs.[36] Newfoundland Power is the only the utility surveyed by Brattle that has an incentive mechanism associated with its supply costs.[37]

Based on the foregoing, the Company submits that the circumstances do not necessitate a specific review of Newfoundland Power's WNR. Further, a revised wholesale rate is expected to significantly reduce the cost variances in the WNR.[38] Finally, Brattle's finding that it is not evident that the Hydrology component should be included in the WNR, or there should be an incentive mechanism attached to it, is inconsistent with the jurisdictional reviews completed by Newfoundland Power, Brattle and Concentric. These reviews all independently provided that mechanisms that permit full recovery of supply costs by investor-owned distribution utilities are commonplace in Canadian regulatory practice.

Supply Cost Mechanism Reviews and Reporting

Newfoundland Power recognizes that more detailed information on its supply cost mechanisms would be beneficial to the Board in its consideration of the Company's future general rate applications. Newfoundland Power will file a report with its next general rate application that provides details on each of its supply cost mechanisms, including a jurisdictional review, to assist the Board in its review of the Company's recovery of supply costs.

[36] If the Company's proposed threshold of ±$500,000 is not approved the threshold would increase to ±$807,723 for 2025 and ±$800,887 for 2026. See the response to Request for Information PUB-NP-074.

[37] See the response to Request for Information NP-PUB-005.

[38] Assuming the revised rate has a second block rate that is closer to Newfoundland Power's average energy supply cost rate of 6.940¢ per kWh than the current second block rate of 18.165¢ per kWh.

3.4 OTHER

Excess Earnings Account

Brattle recommended that it would be beneficial if the Excess Earnings Account was based on Newfoundland Power's approved return on equity rather than its return on rate base.[39] However, Brattle noted that this issue has been previously considered by the Court of Appeal of Newfoundland and Labrador, and that the Court determined there are limits on the Board's jurisdiction in this matter. Newfoundland Power agrees with Brattle's finding.

Total Deferral Account Coverage

Brattle also provided its assessment of Newfoundland Power's total deferral account coverage compared to other investor-owned Canadian electric utilities. Brattle found that:

> *"NP [Newfoundland Power] has a similar amount and treatment of deferral coverage to other utilities. However, many of these other utilities have some form of incentive regulation that requires them to find efficiencies for large portions of their costs. NP lacks this additional incentive to reduce costs and find efficiencies while also benefiting from a similar amount of deferral account coverage."*[40]

In Newfoundland Power's view, Brattle's analysis oversimplifies the regulation framework used in each jurisdiction to suggest a particular form of regulation requires utilities to find cost efficiencies, while another form of regulation lacks the additional incentive for the utility to find efficiencies.[41] Brattle does not appear to consider the local circumstances that gave rise to the approach to regulation in each jurisdiction.[42] In the Company's view, regulators across Canada

---

[39] See Brattle, *Review on Newfoundland Power's Deferral Accounts,* prepared by Philip Q. Hanser and Adam Wyonzek, April 24, 2024, page 20.

[40] Ibid., page 24.

[41] See, for example, the response to Request for Information NP-PUB-004.

[42] Ibid.

are striving to ensure customer electricity rates reflect efficient utility operations by working within the rate-setting framework permitted by their local legislation.[43]

In Newfoundland and Labrador, the Board tests operational efficiencies through the review of utility general rate and capital budget applications.[44] The Board has also established a range of return on the utility's rate base, which provides an incentive for the utility to find operational efficiencies between rate reviews which are ultimately passed onto customers in the next rate-setting process.[45]

Newfoundland Power observes that the range of returns on equity ("ROE") are significantly larger in PBR and MRP jurisdictions than in more traditional COS jurisdictions.[46] In theory, the larger range, along with prolonged period between general rate proceedings, can provide a larger incentive to a utility to find cost efficiencies.

---

[43] This is reflective of the power policy set out in each province. In most cases, including Newfoundland and Labrador, the power policy makes specific reference to operational efficiency requirements.

[44] Newfoundland Power has demonstrated sound cost management and a dedication to improving its operating efficiency. See, for example, the response to Request for Information PUB-NP-140.

[45] See, for example, Order No. P.U. 36 (1998-99), where the Board approved an increase in the range of return on Newfoundland Power's rate base from 24 basis points to 36 basis points. In that order, the PUB stated on page 70: "*The introduction of an expanded range of 36 basis points will provide an incentive for the company to improve productivity and will allow for some variation in financial variables other than those adjusted by the formula.*"

[46] In Ontario, the range of ROE is ±300 basis points. In Alberta, the range of ROE is ±200 basis points. If a utility's actual ROE is between 200 and 400 basis points higher than the ROE used to set customer rates, the utility retains 60% and customers receive 40% of the incremental earnings in that range. For earnings more than 400 basis points above the rate-setting ROE for that year, the utility retains 20% and customers receive 80% of incremental earnings. For FortisBC, any actual earnings below or above the mid-point ROE in that year are shared 50/50 with customers through the symmetrical Earnings Sharing Mechanism. Further, the MRP allows for a plan off-ramp to be triggered if earnings in any one year vary from the ROE by more than ±150 basis points. This compares to ranges on ROE in traditional COS jurisdictions of ±25 basis points to +35 basis points for Nova Scotia Power and Maritime Electric, respectively, as well as ±18 basis points on return on rate base for Newfoundland Power.

Ultimately, Newfoundland Power is regulated under a COS model as established by provincial legislation. While other forms of regulation may provide opportunities, a review of the established rate-setting framework for utilities in the Province is outside of the scope of this proceeding.[47] For the 2025/2026 GRA, the Board's testing of Newfoundland Power's operating costs, consistent with its prior Board orders and practices, remains appropriate and reasonable.

Finally, Brattle's finding that "*NP lacks this additional incentive to reduce costs and find efficiencies while also benefiting from a similar amount of deferral account coverage*" is based on a limited analysis and is therefore not appropriate.[48] An example would be a comparison of 2024 cost recovery between FortisBC under its MRP framework and Newfoundland Power under its COS model. For 2024, Newfoundland Power has a more limited ability to recover its costs without a fulsome regulatory review as compared to FortisBC.

Under the MRP approach, FortisBC's 2024 revenue deficiency for the upcoming year is recovered through an annual customer rate change.[49] The MRP allows for annual recovery of all changes in FortisBC's revenue requirement, such as sales, depreciation, operating expenses and return on rate base.[50] In comparison, the recovery of Newfoundland Power's 2024 revenue deficiency is limited to only the return on rate base component of its revenue requirement. It

---

47 For example, in Alberta, the time between the regulator announcing its intent to adopt PBR and issuing its PBR decision was 33 months.

48 See part g) to the response to Request for Information NP-PUB-004.

49 See, for example, page 7 of FortisBC's *Multi-Year Rate Plan for 2020 through 2024, Annual Review for 2024 Rates,* August 4, 2023.

50 Ibid. As outlined on page 8, FortisBC establishes the majority of its operating and maintenance ("O&M") expense by a formula approved by the BCUC during the MRP term. As provided by FortisBC on page 8, the O&M formula incorporates a net inflation factor of 3.580 percent, which is inclusive of a productivity improvement factor (X-Factor) of 0.5%, and uses a forecast of the change in average customers.

does not include any recovery for increased depreciation and operating costs pressures since the 2023 test year.

SECTION 4: RECOMMENDATIONS OF C. DOUGLAS BOWMAN

4.1 OVERVIEW

In the Bowman Evidence, C. Douglas Bowman ("Mr. Bowman") provided 14 recommendations for the Board to consider in its order on Newfoundland Power's 2025/2026 GRA. These recommendations were primarily in the areas of rate design, cost of service, and distribution planning and reliability.

The Bowman Evidence did not provide comprehensive studies, jurisdictional comparisons, or customer benefit and cost analyses to support its recommendations. Overall, the recommendations appear to be primarily based on Mr. Bowman's opinion of certain information on the record of this proceeding, as well as his prior work experiences and engagements.[51]

The following provides Newfoundland Power's rebuttal to the Bowman Evidence. The rebuttal primarily relies on information on the record of this proceeding. The purpose of Newfoundland Power's rebuttal is to clarify the circumstances and information underpinning Mr. Bowman's recommendations.

4.2 RATE DESIGN AND MARGINAL COSTS (Recommendations #1, #7, #8, #9)

The Bowman Evidence recommends that the Board direct Newfoundland Power and Hydro to submit a re-designed wholesale rate by August 2024 so that it can be incorporated in the Board's order on the Company's 2025/2026 GRA and implemented by January 1, 2025.[52]

---

[51] See, for example, the response to Request for Information NP-CA-037.

[52] See *Pre-Filed Evidence of C. Douglas Bowman,* April 17, 2024, page 4, lines 3-5.

Discussions between Newfoundland Power and Hydro regarding the implementation of a new wholesale rate effective January 1, 2025 are ongoing. As outlined in the responses to Requests for Information PUB-NP-004 and PUB-NP-132, the process to implement a new wholesale rate would be separate and follow the completion of Newfoundland Power's 2025/2026 GRA process. Hydro would file an application no later than September 2024 proposing a new wholesale rate. The Company would file a subsequent application to "flow-through" the new wholesale rate to its customers. This approach is consistent with past regulatory practice when implementing a new wholesale rate and provides for the implementation of a new wholesale rate by January 1, 2025.

Mr. Bowman's recommendation for Newfoundland Power and Hydro to re-design the wholesale rate as part of the Company's ongoing 2025/2026 GRA is not practical or achievable. As indicated, Newfoundland Power is working with Hydro with a goal to establishing a new wholesale rate by January 1, 2025.

Mr. Bowman also recommends that retail rates be redesigned to reflect marginal supply costs, including introducing a tail-block energy charge for domestic customers, as part of the Board's order on Newfoundland Power's 2025/2026 GRA and implemented on January 1, 2025.[53] In support of his recommendations, Mr. Bowman provides that:

> "*Newfoundland Power does not need to wait for a consultant's report to re-design its retail rates with tail-block energy charges that reflect marginal costs consistent with past Board direction, the regulatory principle of practical attributes, and government electrification and net-zero emissions efforts.*"[54]

---

53 See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 8, lines 13-21. In addition, in response to Request for Information PUB-CA-020, Mr. Bowman stated that new rate designs can be developed between May 21, 2024 and June 13, 2024 in time for a Board order on the 2025/2026 GRA.

54 See *Pre-Filed Evidence of C. Douglas Bowman,* April 17, 2024, page 30, lines 23-26.

In addition to recommendations to change Newfoundland Power rate designs as part of the 2025/2026 GRA, Mr. Bowman recommends giving priority to implementation of additional rate options on an experimental and optional basis as part of the stakeholder review of the Phase 1 report of the Rate Design Review.[55]

Newfoundland Power proposes changes to its customer rate structures based on comprehensive reviews.[56] As described in the Scope of Work for the Rate Design Review, this includes analysis of customer rate alternatives, customer rate impacts, cost of service implications, and engagement with stakeholders.[57] Mr. Bowman has not provided any such analysis or stakeholder engagement in support of his recommendations. Completing a comprehensive review is necessary to ensure any new rate designs appropriately meet established regulatory principles, are acceptable to customers, and do not result in unintended consequences.[58] For example, establishing a declining block rate structure for Domestic customers, as recommended by Mr. Bowman, may encourage customers to consume more energy during winter peak periods when capacity on the Island Interconnected system is limited.[59] This could create system reliability

[55] See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 8, lines 22-27.

[56] Newfoundland Power's current customer rates largely reflect the recommendations of the Company's *Retail Rate Review* which commenced in 2008 and was used to inform rate proposals included in the Company's *2013 General Rate Application*. Initial changes in the Company's rate structures recommended from the Company's *Retail Rate Review* were approved, beginning in Order No. P.U. 13 (2013).

[57] See the response to Request for Information CA-NP-257, Attachment A for the Scope of Work in relation to the ongoing Rate Design Review. The Consumer Advocate was engaged in the development of the Scope of Work. All input received from the Consumer Advocate was incorporated into the Scope of Work before it was finalized.

[58] Newfoundland Power is guided by the Criteria for Sound Rate Structure described by James Bonbright in *Principles of Public Utility Rates, 2nd Ed, 1988.* The principles include: effectiveness, practicality, stability, efficiency, and fairness.

[59] See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 33, lines 8-15.

concerns and further increase the need for additional capacity on the Island Interconnected System.[60]

Newfoundland Power does not agree with Mr. Bowman's recommendations to implement changes in rate designs as part of the 2025/2026 GRA.[61] However, the Company is committed to working with the Consumer Advocate and Mr. Bowman as part of the ongoing Rate Design Review.

4.3 GENERAL COST OF SERVICE MATTERS (Recommendations #2, #6)

The Bowman Evidence recommends that Newfoundland Power give highest priority to the Load Research Study, and that it should be completed by the spring of 2026.[62]

Newfoundland Power provided an update on its Load Research Study in its response to Request for Information PUB-NP-169. In its update, Newfoundland Power outlined the work completed in relation to the Load Research Study to date and outlined work to be completed in 2024 and future years. The response explained that the necessary meters were delayed due to supply chain constraints, which have impacted the utility industry in recent years. Meters are expected to be received throughout 2024, which will permit Newfoundland Power to collect customer load data

---

60 In its *Reliability and Resource Adequacy Study – 2022 Update*, *Volume 3*, October 3, 2022, page 51, Hydro stated that the Island Interconnected System will be significantly capacity constrained once the Holyrood Thermal Generating Station and Hardwoods Gas Turbine are retired. Hydro is currently assessing future capacity additions to meet the needs of the Island Interconnected System.

61 See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 8, lines 13-27.

62 Ibid., page 5, lines 17-20.

over the 2024-2025 and 2025-2026 winter seasons. The Company recognizes the importance of the Load Research Study and is not able to advance its completion given the requirement to collect data over two winters. Mr. Bowman's recommendation to give highest priority to the Load Research Study is redundant in consideration of the Company's ongoing efforts.[63]

The Bowman Evidence also recommends that Newfoundland Power "*bring rates for the Street and Area Lighting customer class up to levels that collect the full cost of supply identified in the cost of service study.*"[64] Mr. Bowman's commentary was limited to the Street and Area Lighting customer class, which has a revenue-to-cost ratio of 97.2%. No commentary or recommendation was provided for other customer classes with a revenue-to-cost ratio lower than 100%, for example, the Domestic customer class which has a revenue-to-cost ratio of 96.5%.

In response to Request for Information PUB-CA-019, Mr. Bowman stated that he *"is not concerned about use of a 90% to 110% range to assess cost recovery"* and that he is also not *"concerned about altering cost recovery within this range.*"[65]

In Order No. P.U. 7 (1996-97), the Board provided that it is not necessary to achieve a 100% revenue-to-cost ratio for all classes and that it takes no exception to a variance of up to 10%. In past general rate applications, the Board has approved customer rates that were determined by applying an average increase to each class of service, to the extent possible when the revenue-to-cost ratio for each class of service was between 90% and 110%. The same circumstances exist in Newfoundland Power's 2025/2026 GRA. Accordingly, the Company's approach to determining

---

[63] See *Pre-Filed Evidence of C. Douglas Bowman,* April 17, 2024, page 5, lines 17-20.
[64] Ibid., page 6, lines 3-7.
[65] See the response to Request for Information PUB-CA-019, page 1, lines 29-30.

its customer rates by applying an average increase to each class of service, to the extent possible, is reasonable, and its application to street lighting rates is within accepted bounds. A revenue-to-cost ratio of 97.2% does not warrant applying a higher than average increase to Street and Area Lighting customers. As such, the Company does not support Mr. Bowman's recommendation with regards to Street and Area Lighting customer rates.[66]

4.4 COST OF SERVICE METHODOLOGY AND POLICIES (Recommendations #3, #4, #5, #10, #11)

The Bowman Evidence includes recommendations involving Newfoundland Power's approved cost of service methodology, *Schedule of Rates, Rules and Regulations*, and *Contribution in Aid of Construction Policy* ("CIAC Policy"). Mr. Bowman's recommendations also involve treatment of costs associated with Memorial University, establishing a new General Service rate (perhaps General Service Rate 2.5), and other matters.[67]

4.4.1 Schedule of Rates, Rules and Regulations and CIAC Policy

Mr. Bowman recommends that Newfoundland Power develop a transparent policy relating to connections, and make amendments as necessary to the *Schedule of Rates, Rules and Regulations* and CIAC Policy to ensure fair and equal treatment of customers.[68]

[66] Ibid.
[67] See *Pre-Filed Evidence of C. Douglas Bowman,* April 17, 2024, page 5, lines 21-36 to page 6, line 2; page 8, line 28 to page 9, line 2; and page 9, lines 3-9.
[68] Ibid., page 5, lines 27-31.

Newfoundland Power applies its Board approved *Schedule of Rates, Rules and Regulations* and CIAC Policy to ensure service is provided to customers in a manner that is non-discriminatory.[69] The existing *Schedule of Rates, Rules and Regulations* and CIAC Policy adequately address the fairness in the recovery of costs associated with serving customers in the Company's various rate classes, including costs associated with connection assets, or assets that serve only one customer.[70]

Section 9(c) of Newfoundland Power's *Schedule of Rates, Rules and Regulations* requires that a customer pay the additional cost of providing special facilities requested by the customer. This applies to facilities that are not part of Newfoundland Power's standard supply arrangements, such as a redundant supply point. Requiring a customer to pay the costs associated with a special facility ensures no other customer bears the cost of such a facility. Newfoundland Power consistently applies section 9(c) of its *Schedule of Rates, Rules and Regulations*.[71]

The purpose of Newfoundland Power's CIAC Policy is to determine the contribution a customer is required to pay toward the cost of their electrical service, including the cost of connection assets. The CIAC Policy recognizes that the cost of serving some customers is greater than the revenue that will be recovered from the customer through rates. In these cases, a contribution is required from the customer to ensure other customers do not bear the cost of providing service to a customer that is in excess of what will be recovered from the customer through rates.[72]

---

[69] See the response to Request for Information CA-NP-162.

[70] Mr. Bowman refers to connection assets, or connection facilities as transmission facilities where flow is primarily in one direction, also known as "radial" facilities. See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 17, lines 1-3.

[71] See, for example, Order No. P.U. 5 (2019) which approved construction of the Long Pond ("LPD") Substation and its determination as a special facility.

[72] See the response to Request for Information CA-NP-137.

Newfoundland Power has been applying its CIAC Policy in accordance with Board orders since the policy was approved in 2005.[73] Hydro uses the same CIAC Policy as Newfoundland Power.[74]

Newfoundland Power's *Schedule of Rates, Rules and Regulations* and CIAC Policy are available to the public on the Company's website.[75] They outline the rates that are charged to customers and when a customer will be required to make a separate contribution towards their electrical service. Regulatory proceedings relating to the *Schedule of Rates, Rules and Regulations* and routine application of the CIAC Policy are a matter of the public record and are available on the Board's website.[76] This ensures transparency in relation to customer contributions.

The Bowman Evidence recommends that Newfoundland Power update the *Schedule of Rates, Rules and Regulations* and CIAC Policy to ensure that connection assets that benefit only one customer are paid for by the benefiting customer, and that a separate policy or rate be developed.[77] As described, Newfoundland Power's *Schedule of Rates, Rules and Regulations* and CIAC Policy ensure the cost of assets that benefit only one customer, including connection assets, are recovered from the benefiting customer either through customer rates or a separate contribution.

73 See Order No. P.U. 27 (2005). The CIAC Policy is updated on an annual basis and was most recently approved by the Board in Order No. P.U. 6 (2024).
74 See the responses to Requests for Information CA-NLH-007 and CA-NLH-013.
75 See Newfoundland Power (n.d.). *Regulation*. Retrieved on May 28, 2024 from https://www.newfoundlandpower.com/en/About/Who-We-Are/Regulation.
76 See Public Utilities Board (n.d.). Applications and Proceedings www.pub.nl.ca/PU_ApplicationsProceedings.php.
77 See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 8, line 28 to page 9, line 2.

Mr. Bowman ignores evidence in this proceeding that demonstrates customers pay an appropriate contribution towards their connections as part of the CIAC Policy. For example, a contribution was required from the Town of Pouch Cove in relation to providing electrical service to a water chlorination plant. The construction of approximately 1.3 km of distribution line was required to connect and serve a relatively small load of approximately 23.2 kW at the Town's water chlorination plant. Since the costs to serve the customer were in excess of the revenue that would be recovered from the customer through rates, a contribution was calculated and paid in accordance with the CIAC Policy.[78] Similarly, Newfoundland Power evaluated the requirements to serve new electric boiler load of approximately 25,000 kW planned at Memorial University. In order to serve the load, an upgrade is required at the LPD Substation.[79] Since the costs to serve the new electric boiler load are less than the revenue that would be recovered from the customer through rates, a contribution was not required by Memorial University in accordance with the CIAC Policy. In each example, the Company filed CIAC Applications with the Board in accordance with the CIAC Policy. The applications were reviewed and subsequently approved by the Board.[80]

Mr. Bowman does not acknowledge the relationship between a contribution made by a customer in accordance with the CIAC Policy and the revenues received from the customer through rates. Further, Mr. Bowman does not provide an example of an alternative policy, or explain how such

---

[78] See the response to Request for Information CA-NP-137, part a).

[79] The Newfoundland Power upgrade at the LPD Substation includes a new 25 MVA 66 kV – 12.5 kV transformer. Memorial University's electric boilers will be supplied from the University's 12.5 kV switch gear equipment which is also located at the LPD Substation.

[80] The CIAC application filed in relation to the Town of Pouch Cove was approved by the Board in Order No. P.U. 34 (2000-2001) and included an approximate $35,000 customer contribution. The CIAC application filed in relation to the new electric boiler load at Memorial University was approved by the Board in Order No. P.U. 5 (2023) and did not require a customer contribution. See the responses to Requests for Information CA-NP-137 and CA-NP-268 for additional details.

a policy would function in consideration of the existing *Schedule of Rates, Rules and Regulations* and CIAC Policy.

Newfoundland Power's existing *Schedule of Rates, Rules and Regulations* and CIAC Policy have functioned, and continue to function to ensure fair and equal treatment of all customers. Notwithstanding the above, the Company recognizes that the CIAC Policy does not specifically define transmission assets or connection assets. While it would not change the Company's approach to contributions required from customers served from the transmission system, Newfoundland Power is supportive of updating the language in the CIAC Policy to provide additional clarity in this regard.[81]

4.4.2 Cost of Service Methodology

Newfoundland Power is not proposing any changes to its approved cost of service methodology as part of its 2025/2026 GRA. The Company's approved cost of service methodology was reviewed in detail, at the request of the Board, as part of the Company's *2003/2004 General Rate Application*.[82] Mr. Bowman stated that a jurisdictional cost of service review was not necessary

[81] Newfoundland Power has two General Service Rate #2.4 customers that are supplied by 66 kV transmission voltage. Both customers paid a CIAC for their electricity service. See the responses to Requests for Information CA-NP-159, part a) and CA-NP-268, footnote 3.

[82] In Order No. P.U. 7 (1996-97), the Board directed Newfoundland Power to provide detailed evidence on the Company's cost of service methodology at its next general rate application. In Newfoundland Power's *2003/2004 General Rate Application*, Newfoundland Power 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 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 were appropriate to be used in establishing 2008 customer rates. At Newfoundland Power's 2010, 2013/2014, 2026/2017, 2019/2020 and 2022/2023 general rate applications, the results of the Company's cost of service study were accepted for use in establishing customer rates.

in support of his recommended changes to Newfoundland Power's approved cost of service methodology. [83]

Newfoundland Power's cost of service methodology includes both the costs to serve a customer and the revenue received from the customer through rates. If, through application of the CIAC Policy, a customer contribution is required for assets that serve only one customer, those costs and the contribution paid by the customer are excluded from the cost of service study. This is because those costs are recovered directly from the customer through a contribution and not through the customer's rates.[84]

Costs associated with specific transmission and substation assets that are associated with an individual customer and that are recovered through the rates charged to the customer are specifically assigned to the customer's rate class in accordance with the approved cost of service methodology.[85] This is to ensure: (i) the costs of serving that customer that do not require a contribution; and (ii) the revenue received from the customer through rates are accounted for in the same rate class in the cost of service study. This enables the Company to assess the fairness of the costs and revenues associated with each rate class (the "revenue-to-cost ratio").[86]

---

[83] See the response to Request for Information NP-CA-037.

[84] The Company's CIAC Policy is applied to all of Newfoundland Power's customers.

[85] See Newfoundland Power's *2003/2004 General Rate Application*, Exhibit LCH-1.

[86] Maintaining revenue-to-cost ratios for each customer rate class within a range of 90% to 110% has been an accepted approach to achieving fairness in rate design by avoiding undue cross-subsidization among the various rate classes. All of Newfoundland Power's customer rate classes are within this threshold. See the 2025/2026 GRA, *Volume 1: Application, Company Evidence and Exhibits, 5.3.1 Embedded Cost of Service Study,* page 5-7, table 5-5.

Mr. Bowman attempts to draw conclusions by equating Hydro's cost of service methodology as it relates to Newfoundland Power with Newfoundland Power's cost of service methodology as it relates to the General Service Rate #2.4 customer rate class. Mr. Bowman states that, once Hydro specifically assigns an asset to Newfoundland Power, all costs associated with ongoing operation and maintenance of the asset are allocated to Newfoundland Power.[87] Unlike Newfoundland Power's General Service Rate #2.4 customer rate class, which includes approximately 60 customers, the Utility rate charged from Hydro to Newfoundland Power is specifically designed for one customer, Newfoundland Power. Mr. Bowman's comparison implies that Newfoundland Power must reproduce this wholesale rate structure at the retail level by designing a specific rate and charges for each of the 60 General Service Rate #2.4 customers. Such a rate design is not practical, nor is it necessary, as the Company's *Schedule of Rates, Rules and Regulations* and CIAC Policy appropriately recover the costs of assets that serve only one customer, either through customer rates applicable to that rate class or contributions paid by the customer.

It is Mr. Bowman's position that Newfoundland Power's cost of service study results are skewed because the costs of connection assets are allocated to all customers rather than only the customers who benefit exclusively from the connection.[88] Mr. Bowman recommends Newfoundland Power change its cost of service methodology to account for assets that benefit only one customer.[89] As per the approved CIAC Policy, customers pay a contribution towards assets that serve only that customer when those costs are not recovered through rates. Under the approved cost of service methodology, costs that are recovered from a customer through rates, as well as the revenue received from the customer through rates, are properly allocated to the

[87] See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 17, lines 28-29.
[88] Ibid., page 38, lines 22-26.
[89] Ibid., page 5, lines 21-26.

customer's rate class. As a result, Newfoundland Power does not agree with Mr. Bowman's recommendations that changes in the Company's cost of service methodology are required to address assets that benefit one customer.

4.4.3 Demand Charge Reduction

Mr. Bowman takes the position that Newfoundland Power's demand charge reduction for customers that own their own transformation and all other facilities beyond the designated point of supply does not "eliminate" cross-subsidization concerns within the approved cost of service methodology.[90]

Newfoundland Power's *Schedule of Rates, Rules and Regulations* includes a demand charge reduction for customers that own their own transformation and all other facilities beyond the designated point of supply.[91] The credit is applied to ensure customers, such as two mines that own their own 66 kV transformers and Memorial University which owns the 12.5 kV transformers supplying load throughout the university campus, pay a lower rate than General Service Rate #2.4 customers that are served from Newfoundland Power's lower voltage distribution systems.[92] This ensures that customers that provide their own transformation and other facilities beyond their point of supply do not unduly subsidize customers that receive service from Newfoundland Power's primary or secondary distribution systems.

---

[90] See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 27, lines 28-32. The demand charge reduction is included in the Company's S*chedule of Rates, Rules and Regulations,* effective July 1, 2023, Section 9(k).

[91] See the Company's *Schedule of Rates, Rules and Regulations,* effective July 1, 2023, Section 9(k). There are 97 General Service customers that own their transformers and all other facilities beyond their point of supply. See the response to Request for Information CA-NP-302.

[92] Newfoundland Power serves two mines at 66 kV transmission voltage. These include a mine located in central Newfoundland and a mine located in western Newfoundland.

The demand charge reduction for customers that own their own transformation and all other facilities beyond the designated point of supply alleviates cross-subsidization concerns within Newfoundland Power's General Service Rate #2.4 customer rate class for customers served at transmission, primary and secondary voltages.[93] The demand charge reduction is within the range of those provided by other utilities.[94] The inclusion and application of the demand charge reduction in Newfoundland Power's *Schedule of Rates, Rules and Regulations* helps ensure rates charged to customers are reasonable and not unjustly discriminatory as required by the *Electrical Power Control Act, 1994* (the "EPCA").[95]

4.4.4 Memorial University

Mr. Bowman maintains several positions regarding cost recovery related to Memorial University as a General Service Rate #2.4 customer. Mr. Bowman argues that Memorial University is being charged a rate that recovers costs for distribution facilities that are not used to supply the university.[96] The General Service Rate #2.4 customer rate class applies to approximately 60 of Newfoundland Power's largest customers including Memorial University. These customers are served by either secondary, primary, or transmission voltages. Customers, such as Memorial University, who are served at primary voltages and subsequently own their own 4 kV to 12.5 kV transformation and all other facilities beyond their point of supply receive a reduced demand charge as explained in *Section 4.4.3. Demand Charge Reduction*. This reduces the charges to customers, such as Memorial University, who do not utilize secondary distribution equipment included in Newfoundland Power's cost of service study. While the General Service Rate #2.4

93 See the response to Request for Information PUB-NP-108.
94 See the response to Request for Information CA-NP-303.
95 See the EPCA, section 3(a)(i).
96 See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 24, line 36 to page 25, line 1.

customer rate class includes equipment that supplies customers at secondary voltages, Mr. Bowman does not acknowledge that Memorial University's charges are lower than General Service Rate #2.4 customers that do require service at secondary voltages for that reason.

Mr. Bowman also takes the position that Newfoundland Power is not charging Memorial University for the cost of facilities that benefit only the university.[97] All of the customers in Newfoundland Power's General Service Rate #2.4 customer rate class are served by dedicated transformers and other assets for the specific use of the individual customer. If Newfoundland Power were to apply the same principle suggested by Mr. Bowman, the Company would have to establish a separate rate or charge for each General Service Rate #2.4 customer that would be specific to their individual service. Such an individualized rate design would be impractical to administer to 60 customers.

In accordance with the Company's CIAC Policy, when the cost to serve an individual customer is in excess of what will be recovered from the customer through rates, a CIAC will be required. This ensures other customers do not subsidize the specific connection assets for any particular customer. For example, the two mines served by the Roycefield ("RFD") Substation and the Lower Cove ("LCV") Substation were required to pay a CIAC since their connections included construction costs that would not be recovered through rates.[98] Mr. Bowman does not acknowledge that a contribution was not required from Memorial University since the costs of

[97] See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 27, line 37 to page 28, line 1.
[98] See the responses to Requests for Information CA-NP-149, part e) and CA-NP-268, footnote 3. Both mines are served by radial transmission lines.

supplying the university, including costs associated with assets that only benefit Memorial University, are recovered through its rates.[99]

Memorial University was required by Newfoundland Power to pay a full contribution towards the construction of the LPD Substation since it was determined to be redundant to Memorial University's primary supply point, MUN Substation. The LPD Substation was considered a special facility in accordance with the Company's *Schedule of Rates, Rules and Regulations.* Newfoundland Power's treatment of the LPD Substation to be fully contributed by Memorial University was reviewed and approved by the Board.[100]

Memorial University was not required to pay a contribution towards costs at MUN Substation. MUN Substation was constructed in 1966 and requires capital expenditures to address failed and aging equipment.[101] Costs associated with MUN Substation that are attributable to Memorial University are adequately recovered through the rates paid by Memorial University. [102] As a result, no contribution was required from Memorial University in relation to the capital expenditures necessary to ensure MUN Substation continues to provide reliable service to Memorial University in the future.

It is also Mr. Bowman's position that transmission lines 12L and 14L which terminate at MUN Substation are radial transmission assets that serve only Memorial University. Mr. Bowman

---

99 See the response to Request for Information CA-NP-137, part e).
100 See Order No. P.U. 5 (2019).
101 Capital expenditures associated with MUN Substation were approved by the Board in Order No. P.U. 14 (2023) and Order No. P.U. 2 (2024).
102 See the response to Request for Information CA-NP-137, part e).

references the National Association of Regulatory Utility Commissioners ("NARUC") definition of radial transmission assets as:

> *"those facilities that are not networked with other transmission facilities, but are used to serve specific loads directly. For cost of service purposes, these facilities may be directly assigned to specific customers on the theory that these facilities are not used or useful in providing service to customers not directly connected to them."*[103]

In relation to the direct assignment of costs associated with specific transmission facilities, NARUC states:

> *"The costs of specific transmission facilities, such as long radial transmission line and substations, may be directly assigned to particular customers. Direct assignments of such costs implies that the facilities can be considered entirely apart from the integrated system. In fact, the case for the independence of the facilities must be unequivocal since the customer must be willing to bear all of the costs of service that, due to the unintegrated character of the facilities, may be just as high for service that is less reliable than service on the integrated system."*[104]

Transmission Lines 12L and 14L, which terminate at MUN Substation, cannot be considered entirely apart from the integrated system. Nor is it unequivocal that transmission lines 12L and 14L exist only to serve Memorial University. Transmission lines 12L and 14L are integral to Newfoundland Power's looped 66 kV transmission network serving thousands of customers in the St. John's region.[105] This was recognized by the Board in its order on Newfoundland Power's *2024 Capital Budget Application*.[106]

Newfoundland Power's treatment of Memorial University is consistent with its approved cost of service methodology, CIAC Policy, and *Schedule of Rates, Rules and Regulations.* As explained,

---

[103] See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 17, lines 6-11.
[104] See NARUC Manual, January 1992, page 83.
[105] See the responses to Requests for Information PUB-NP-106, CA-NP-154, CA-NP-155, CA-NP-165 and CA-NP-275.
[106] See Order No. P.U. 2 (2024) Reasons for Decision, page 12, line 36 to page 13, line 2.

this ensures the rates charged to Memorial University are consistent with the Company's legislative requirement that rates be reasonable and not unjustly discriminatory.

The appropriateness of Newfoundland Power's treatment of costs associated with Memorial University has been recognized in recent Board orders and correspondence. In response to the Consumer Advocate's request to rehear the Company's application for supplemental expenditures associated with the replacement of the MUN-T2 transformer, the Board stated:

> *"The Board is satisfied that the treatment of the MUN-T2 transformer replacement at Memorial Substation is consistent with Newfoundland Power's approved cost of service and longstanding regulatory principles and is in no way unfair or discriminatory."*[107]

Newfoundland Power commenced a Rate Design Review in 2023 which is anticipated to be completed by 2026. In addition to the Rate Design Review, the Company also plans to complete a review of the rates charged to Memorial University due to the anticipated large changes in the customer's load profile in the coming years due to the planned installation of electric boilers, the addition of new buildings and the potential establishment of a capacity assistance agreement. This review will provide an analysis of all costs associated with providing service to Memorial University and will consider whether any changes to Newfoundland Power's General Service Rate #2.4 rate structures are appropriate.[108]

---

[107] See page 2 of the Board's correspondence *Re: Newfoundland Power Inc. – 2023 Capital Budget Supplemental Application – Approval for the Purchase and Installation of a Replacement Power Transformer for Memorial Substation – Response to Consumer Advocate's Request for Re-hearing of Application*, dated July 7, 2023. See also, Order No. P.U. 14 (2023) and P.U. 2 (2024).

[108] See the response to Request for Information PUB-NP-160.

The Board agreed with Newfoundland Power's approach as part of the Company's *2024 Capital Budget Application*. In its order on the *2024 Capital Budget Application*, the Board stated:

> *"The Board notes that the annual revenue requirement associated with capital expenditures which are not fully contributed by a customer is recovered through customer rates over the life of the assets... A review of the rates charged to MUN may be appropriate when more information is known about the anticipated changes in its load profile and when the ongoing rate design review by Newfoundland Power is complete."*[109]

Mr. Bowman's positions and recommendations in relation to the treatment of costs associated with Memorial University are addressed by the Company's approved *Schedule of Rates, Rules and Regulations,* CIAC Policy and cost of service methodology. For this reason, Newfoundland Power does not agree with Mr. Bowman's recommendations in relation to Memorial University.[110]

4.4.5 New Rate Class (Rate 2.5)

It is Mr. Bowman's position that Newfoundland Power should be required to make changes to its cost of service methodology, including the creation of an additional General Service Rate Class for three customers ("perhaps General Service Rate #2.5"). Mr. Bowman recommends the new rate class be established in 2024.[111]

The new rate class proposed by Mr. Bowman would be applicable to two mines that are connected directly to Newfoundland Power's 66 kV transmission system and Memorial University, which is supplied at 12.5 kV from the LPD and MUN Substations.[112] Each of these customers were General Service Rate #2.4 customers at the time of the last cost of service review

---

[109] See Order No. P.U. 2 (2024) Reasons for Decision, page 13, lines 9-15.
[110] See *Pre-Filed Evidence of C. Douglas Bowman,* April 17, 2024, page 5, lines 21-26.
[111] Ibid., page 5, line 32 to page 6, line 2.
[112] Ibid., page 35, lines 25-28.

and, with the exception of the addition of the fully contributed LPD Substation, also receive electrical service in the same configuration that existed at the time the last cost of service review was completed.[113]

The customers in Newfoundland Power's General Service Rate #2.4 customer rate class are served at secondary, primary, and transmission voltages. Inclusion of customers served by transmission and primary voltages in the General Service Rate #2.4 customer rate class has not changed since the rate was first established in 1987.[114] As outlined in Section *4.4.4 Memorial University*, the Company's existing *Schedule of Rates, Rules and Regulations* and CIAC Policy adequately address cost recovery associated with the three referenced customers.

Newfoundland Power is currently in the process of conducting a Rate Design Review. The purpose of the Rate Design Review is to review existing Domestic and General Service rate designs, review potential alternative rate designs and evaluate the impact of alternative rate designs on Newfoundland Power's customers. Newfoundland Power is also in the process of completing a Load Research Study to inform demand allocations within the cost of service study.[115]

---

[113] General Service Rate #2.4 was established in 1987 following Order No. P.U. 17 (1987). The mine served from the LCV Substation came into operation in 1989. The mine served from the RFD Substation came into operation in 1997. Memorial University has been served from the MUN Substation since it was first constructed in 1966. Memorial University fully contributed the cost of the LPD Substation since it was considered to be a special facility in accordance with the Company's *Schedule of Rates, Rules & Regulations.* See Order No. P.U. 5 (2019).

[114] See Order No. P.U. 17 (1987).

[115] See the response to Request for Information PUB-NP-169.

In developing the framework and scope of work for the Rate Design Review, Newfoundland Power invited input from the Consumer Advocate and Hydro. The Company received feedback from the Consumer Advocate which was incorporated into the framework and scope of the work.[116] Mr. Bowman's recommendations regarding a new General Service rate class were not provided by the Consumer Advocate as feedback to Newfoundland Power as part of the ongoing Rate Design Review and Load Research Study.

Newfoundland Power does not agree with Mr. Bowman's recommendations to make changes to the Company's cost of service study and establish a new General Service rate in 2024.[117] Changing Newfoundland Power's cost of service methodology, including the introduction of a new rate class for three customers in 2024, is premature and not appropriate without detailed review of Newfoundland Power's customer rates in consideration of the ongoing Rate Design Review and Load Research Study.

4.4.6 Other

Interconnection Agreements

Mr. Bowman recommends that Newfoundland Power establish interconnection agreements with customers directly connected to the transmission system. Mr. Bowman suggests that this is important because electrical disturbances at a customer site that is served at 66 kV can cascade

[116] Newfoundland Power filed its *Load Research and Rate Design Framework* with the Board on December 30, 2022. An update regarding the Rate Design Review was provided to the Board as part of the Company's 2023 Annual Report as directed by the Board. A copy of the update was provided in the response to Request for Information PUB-NP-169.

[117] See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 5, line 32 to page 6, line 2.

through the transmission system, causing significant unreliability events to other customers on the system and that the existing CIAC Policy did not envision this scenario.[118]

All Newfoundland Power customer wiring and installations are required to comply with all statutory and regulatory requirements, including the Canadian Electrical Code, and where applicable, in accordance with Newfoundland Power's specifications.[119] In addition, Newfoundland Power's *Schedule of Rates, Rules and Regulations* enables the Company to take measures to ensure a customer's load does not cause undue interference with service to other customers.[120] Newfoundland Power's existing requirements for customers connecting to the electricity grid have ensured cascading transmission outages do not occur.

Newfoundland Power has not experienced any cascading transmission outages owing to its 66 kV customers. As a result, the Company does not agree with Mr. Bowman's recommendation to establish the suggested interconnection agreements.

Memorial University as a Public Utility

Mr. Bowman states that consideration should be given to whether Memorial University should be considered a public utility under the regulatory auspices of the Board.[121] Mr. Bowman does not provide evidence in support of his statement. Consideration of Memorial University as a

---

118 See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 38, lines 15-21.
119 See the response to Request for Information CA-NP-302, part e).
120 Section 5(f) of the *Schedule of Rates, Rules and Regulations* states: *"Where the Company has reason to believe that Service to a Customer has or will have load characteristics which may cause undue interference with Service to another Customer, the Customer shall upon written notice by the Company provide and install, at his expense and within a reasonable period of time, the equipment necessary to eliminate or prevent such interference.*"
121 See *Pre-Filed Evidence of C. Douglas Bowman,* April 17, 2024, page 35, line 31 to page 36, line 6.

public utility would be a matter for consideration by the Board, Memorial University, and other stakeholders, and is outside the scope of Newfoundland Power's 2025/2026 GRA.

4.5 DISTRIBUTION PLANNING AND RELIABILTY (Recommendations #13 and #14)

4.5.1 Reliability

The Bowman Evidence recommends that Newfoundland Power target reliability that is comparable to the Canadian average. Mr. Bowman also recommends that the Company modify its next customer survey to include, among other things, questions on customer willingness to pay for reliability.[122]

Newfoundland Power's reliability performance has been reasonably consistent over the past decade. During that period, the average frequency of outages experienced by Newfoundland Power's customers has been broadly consistent with the Canadian average under normal operating conditions. The average duration of outages experienced by Newfoundland Power's customers has been approximately 40% better than the Canadian average under normal operating conditions.[123] Since the frequency of Newfoundland Power's customer outages is consistent with the Canadian average, Mr. Bowman's recommendation implies that the Company should slow its response to customer outages.

[122] See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 9, lines 32-36.
[123] See the 2025/2026 GRA, *Volume 1: Application, Company Evidence and Exhibits, 2.3.2 Electrical System Reliability*, page 2-16 to 2-23.

Newfoundland Power does not seek overall reliability and service improvements, nor is its capital spending driven by overall reliability improvements.[124] The Company seeks to maintain current levels of reliability and considers its current levels of capital and operational investment to be consistent with the provision of least-cost reliable service to customers.[125]

Newfoundland Power's capital planning process is a deliberate effort to balance the cost and reliability of service provided to customers.[126] In Newfoundland Power's view, a reliable power system can also be a more efficient power system to operate.[127]

Mr. Bowman suggests that there is an incremental cost associated with improving the average duration of customer outages ("SAIDI") and questions whether Newfoundland Power could maintain a prompt response to customer outages if it terminated staff.[128] Newfoundland Power employees that are responsible for responding to customer outages are also responsible for maintaining the integrity of the electrical system.

Newfoundland Power's planned operational investments related to maintaining or replacing assets when they are at or near the end of their service life appropriately minimizes unplanned

---

[124] Newfoundland Power's *Distribution Feeder Automation* capital project is related to improving the efficiency of the Company's system restoration response. It has accounted for less than 1% of the Company's capital investment since 2014. Newfoundland Power's *Distribution Reliability Initiative* is related to improvements in reliability performance for customer served by the Company's worst performing distribution feeders, and has accounted for approximately 1% of capital investments since 2014. See the response to Request for Information PUB-NP-149 for further information.

[125] See the responses to Requests for Information PUB-NP-039, PUB-NP-047, PUB-NP-148 and PUB-NP-149.

[126] Newfoundland Power's capital planning process results in the justified capital expenditures included in the Company's annual capital budget applications. The Board has recognized that fully justified capital expenditures contribute to the delivery of least-cost service to customers. See Order No. P.U. 7 (2002-2003), page 31.

[127] See the response to Request for Information PUB-NP-040.

[128] See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 47, lines 4-8.

customer outages that occur when those assets fail while in service. Unplanned work typically takes longer to complete and often occurs outside normal operating hours, requiring more resources, resulting in a costlier response. An approach focused less on operational investments related to aging equipment is likely to lead to more frequent and costly unplanned outages. This approach would not result in a reduction in employees and is likely to have the opposite effect. More time and resources are required to respond to unplanned customer outages caused by equipment failures.[129] Capital expenditures related to operational technologies and automation also serve to minimize labour costs associated with customer outages while also providing reliable service.[130]

In response to Request for Information NP-CA-038, Mr. Bowman recognizes that, if a utility fails to maintain its asset base, there will be increased risk of injury to the public and utility staff, increased risk of environmental degradation, increased operating and maintenance costs and a decline in reliability performance. Mr. Bowman further states that, depending on the situation, the cost to replace or refurbish an asset might be exceeded by the increase in operating and maintenance cost if the asset is not replaced or refurbished. Nevertheless, it is Mr. Bowman's opinion that Newfoundland Power would find a way to provide reliability consistent with Canadian averages while safely reducing capacity and operating costs if directed to do so.

Targeting a decreased level of reliability, as Mr. Bowman suggests, and allowing reliability performance to degrade over time would be imprudent for a number of reasons. First, there are

[129] See the response to Request for Information CA-NP-293.
[130] See the 2025/2026 GRA, *Volume 1: Application, Company Evidence and Exhibits, 2.3.4 Operating Efficiency*, page 2-27. See also the responses to Requests for Information PUB-NP-017 and PUB-NP-039.

several factors posing a risk to the current levels of reliability experienced by customers. These factors include: aging utility assets; increasing weather events; uncertainties around supply adequacy and bulk transmission reliability; and electrification of energy.[131] These risk factors increase the importance of maintaining the reliability performance of the electrical system. Second, intentionally allowing system reliability to degrade would not contribute to the delivery of least-cost electrical service to customers in the near or long term as the electricity system becomes less reliable.[132]

Mr. Bowman suggests that Newfoundland Power is unable to provide evidence that customers are willing to pay for levels of reliability that are better than the Canadian average.[133] Newfoundland Power has previously established that customer opinions on the value they place on reliable service can be difficult to ascertain.[134] For example, the results of Hydro's Digital Engagement Initiative were reviewed by the Board's consultant, the Liberty Consulting Group ("Liberty"). Liberty found that the initiative did not provide substantial guidance in analyzing the trade offs between cost and reliability. In its review, Liberty stated:

> *"Hydro surveyed customers to understand their preferences between reliability and cost. The results, while interesting, do not provide substantial guidance in analyzing specific tradeoffs between cost and reliability here.*[135]

This is consistent with the Alberta Utilities Commission (the "AUC") which rejected a proposal by the Office of the Utilities Consumer Advocate (the "UCA") for a willingness-to-pay study to set targets due to acceptable reliability and customer satisfaction performance by the Alberta distribution companies. In Decision 2012-237 (September 12, 2012) the AUC provided:

---

131 See part c) of the response to Request for Information PUB-NP-148 for further information.
132 See the response to Request for Information PUB-NP-047 for further information.
133 See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 46, lines 26-28.
134 See the response to Request for Information CA-NP-004.
135 Ibid.

> *"With respect to the willingness-to-pay study proposed by the UCA, the Commission does not consider that such a proposal is necessary. Although a willingness-to-pay study may provide valuable information if the Commission were trying to ascertain whether Alberta distribution companies were providing a socially optimal level of reliability, at this time, the evidence on the record of this proceeding demonstrates that reliability standards are acceptable. Customer satisfaction scores are already provided by the companies on an annual basis as a part of the AUC Rule 002 results. The Commission is of the view that declining customer satisfaction scores will be a timely indicator of problems. For all of these reasons, the Commission rejects the UCA's proposal to use a willingness-to-pay study to set target measures at this time."*[136]

Mr. Bowman has not undertaken a survey or provided evidence of what utilities in Canada collect data relating to customer willingness to pay.[137]

Notwithstanding the established difficulty in ascertaining customer opinions on the value they place on reliable service, Newfoundland Power has had consistent customer satisfaction and reliability performance over the last decade. For this reason, Newfoundland Power does not support Mr. Bowman's recommendation to effectively extend the duration of customer outages and survey customers' willingness to pay for reliability.

4.5.2 Distribution Planning

Mr. Bowman recommends that Newfoundland Power develop new distribution planning guidelines in 2024 which would be included in the Board's Order on the 2025/2026 GRA.[138]

---

[136] See the response to Request for Information CA-NP-004.
[137] See the response to Request for Information NP-CA-039.
[138] See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 10, lines 1-7.

Newfoundland Power's current distribution planning processes adequately address all objectives that Mr. Bowman suggests are required to be met for a "distribution planning guideline."[139] The following documents satisfy a number of Mr. Bowman's stated objectives: the *Distribution Planning Guidelines,*[140] which outline technical criteria and principles for planning the distribution system, including net metering,[141] and the *Service and Metering Guide,* which outlines the Company's policies and procedures as well as technical requirements for establishing electrical service connection and metering to the system.[142] A copy of the *Service and Metering Guide* is available on the Company's website.[143]

Newfoundland Power was also a contributor to and sponsor of the *Distribution Planner's Manual* produced by the Distribution Line Asset Management Interest Group of the Centre for Energy Advancement through Technological Innovation ("CEATI").[144] The *Distribution Planner's Manual* is a comprehensive source of industry standard distribution planning practices and guidelines available to the 36 participating electric utilities, including Newfoundland Power. The Company uses this manual to inform its *Distribution Planning Guidelines* and ensure Newfoundland Power's distribution planning is consistent with industry practice.[145]

---

[139] See *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 43, lines 19-34.

[140] See Attachment A to the response to Request for Information CA-NP-121 for a copy of the *Distribution Planning Guidelines.*

[141] The *Distribution Planning Guidelines* satisfies objectives a) and c) found at page 43 of the *Pre-Filed Evidence of C. Douglas Bowman*, and areas 1 and 3 found at page 45 of the *Pre-Filed Evidence of C. Douglas Bowman.*

[142] The *Service and Metering Guide* satisfies objective d) found at page 43 of the *Pre-Filed Evidence of C. Douglas Bowman*, and areas 3 and 4 found at page 45 of the *Pre-Filed Evidence of C. Douglas Bowman*.

[143] See https://www.newfoundlandpower.com/Business-Services/Contractors-and-Developers/Checklists-and-Resources.

[144] CEATI is a solution-driven network for power industry professionals with an active participation from over 155 member utilities worldwide. CEATI provides its members with practical research, expert guidance, and forums for knowledge exchange. See https://www.ceati.com/about-us.

[145] This satisfies objective f) found at page 43 of the *Pre-Filed Evidence of C. Douglas Bowman*, and area 2 found at page 45 of the *Pre-Filed Evidence of C. Douglas Bowman*.

Newfoundland Power's System Planning Department coordinates regularly with Hydro's System Planning Group. This includes joint system planning meetings, as well as the preparation of analyses of all of Newfoundland Power's looped transmission lines, which are inputs into Hydro's annual Transmission Planning Assessment published on the Newfoundland and Labrador System Operator website.[146]

Newfoundland Power's distribution planning processes, documentation, and participation in industry organizations and with peers ensures proper planning of the distribution system. As a result, the Company does not support Mr. Bowman's recommendation to develop a new distribution planning guideline as part of the 2025/2026 GRA.

4.6 ADVANCED METERING INFRASTRUCTURE (Recommendation #12)

Mr. Bowman recommends that Newfoundland Power conduct a study of the costs and benefits of Advanced Metering Infrastructure ("AMI") technology with the ultimate goal of replacing the current Automated Meter Reading ("AMR") technology, which was implemented by the Company in 2017.[147]

Mr. Bowman asserts that AMR is now "effectively obsolete."[148] This is incorrect. Obsolete products are those which are "*no longer produced by the manufacturer in accordance with the*

[146] This satisfies objectives b) and e) found at page 43 of the *Pre-Filed Evidence of C. Douglas Bowman*.
[147] See the *Pre-Filed Evidence of C. Douglas Bowman*, April 17, 2024, page 9, lines 10-19.
[148] Ibid., page 39, line 8.

original specification."[149] Major meter manufacturers such as Itron continue to sell and support AMR technology.[150] Additionally, AMR technology is still used by numerous electric utilities.[151] Within Canada, for example, AMR technology is used by Manitoba Hydro, Hydro and Northland Utilities. The purported obsolescence of AMR technology does not provide a clear rationale for a transition to AMI, as suggested by Mr. Bowman. The Company's AMR technology provides an efficient and cost-effective way to read customer meters.

Newfoundland Power recognizes that AMI metering technology can provide a range of benefits; however, these benefits can vary by situation and jurisdiction. For example, Newfoundland Power has already realized a large portion of the meter reading cost savings when moving from manually read meters to AMR meters. Additionally, the potential benefits from rate design, such as time of use rates, vary by jurisdiction.[152]

Newfoundland Power is mandated by legislation to provide service at the lowest possible cost consistent with reliable service, delivered in an environmentally responsible manner. The implementation of AMI meters at the present time does not facilitate least-cost provision of service for a number of reasons. First, annual meter investments are required for new customer

---

[149] As defined by the International Electrotechnical Commission: https://www.cyber.gc.ca/en/guidance/obsolete-products-itsap00095. The definition continues: "*Product vendors make a strategic decision to sunset a product to intentionally phase it out or retire it. Vendors may also abandon product lines if they become too expensive to run or maintain. As such, they will stop providing support (security updates, bug fixes, and feature upgrades) for older versions of their products.*"

[150] Further, Newfoundland Power's meter supplier, Itron, has not given the Company any indication that AMR meters will no longer be supported.

[151] See the response to Request for Information CA-NP-034.

[152] Dunsky Energy Consulting concluded that pricing options to encourage peak load management would not provide sufficient benefit to justify the cost of AMI investments at the time. It was also estimated that the benefits of AMI would likely not exceed the costs until at least 2030. See the response to Request for Information CA-NP-034, Attachment B, page 1.

connections and in cases where meters have deteriorated or fail.[153] It is not least cost for Newfoundland Power to provide AMI meters when a new or replacement meter is required. Additionally, AMI metering technology requires unique supports, such as meter reading technology and communications infrastructure. Maintaining two types of meter reading technology would result in additional costs to the Company and would take time to design and implement. Were the Board to disallow further AMR installations, the Company would be precluded from completing sufficient due diligence when choosing a metering replacement.

Newfoundland Power continues to refine its plans for AMI based on the technology's ability to contribute to the provision of least-cost, reliable service delivered in an environmentally responsible manner. Over the last decade, the Company has completed periodic analyses to determine when AMI technology may become cost effective for customers.[154] The Company uses the data provided by third-party consultants from these periodic reviews, as well as internal data, to model the costs and benefits associated with the implementation of AMI, including net present value analyses and payback periods.[155] The Company has monitored government funding opportunities and twice applied for funding in relation to AMI-related projects.[156]

Most recently, the Company has engaged The Posterity Group to complete a market potential study that will examine opportunities for electrification, energy efficiency and demand response,

---

153 Revenue metering of electrical service is regulated under the *Electricity and Gas Inspection Act* (Canada). Pursuant to these regulations, meters are required to be removed from service and tested at specified intervals to ensure accuracy. The Board approved a capital spend of $302,000 for new meters and $571,000 for replacement meters in Order No. P.U. 2 (2024).

154 For example, the previous potential study completed by Dunsky Energy Consulting in 2019.

155 The Company has engaged Capgemini to assist with its AMI cost benefit analysis. Capgemini has consulted on AMI projects for Canadian utilities such as Manitoba Hydro, BC Hydro, Hydro One and Hydro Quebec.

156 See the response to Request for Information CA-NP-250.

including dynamic rate design (the "Potential Study").[157] The Potential Study is underway and will be completed by the end of September 2024. The Potential Study will provide an updated estimate of the potential demand response benefits of rate design, and the results of this updated estimate will be used as an input in the Company's model to produce a revised cost benefit analysis.

The next steps taken by the Company will be guided by the output of the revised cost benefit analysis. If the analysis suggests that AMI implementation may be feasible in the near term, the Company will proceed to complete a comprehensive analysis with the end goal of submitting the analysis to the Board as justification for the proposed AMI capital project. If the analysis suggests that AMI implementation is not feasible in the near term, the Company will continue to revisit and update its cost benefit analysis from time to time and as new information becomes available, such as advancements in AMI technology or changes to costs.

As such, Newfoundland Power does not agree with the recommendation of Mr. Bowman to complete the AMI study by year-end 2024. The Company's review of AMI is ongoing. The ultimate extent of the review (i.e. whether it continues to a comprehensive analysis suitable for provision to the Board for justification of a proposed AMI capital project) will be informed by the outcome of each sequential step in the review process.

[157] See the response to Request for Information CA-NP-034.

SECTION 5: GOVERNMENT RATE MITIGATION PLANS

5.1 RECENT GOVERNMENT RATE MITIGATION ANNOUNCEMENT

The Government of Newfoundland and Labrador announced the finalization of its rate mitigation plan (the "Rate Mitigation Plan") on May 16, 2024.[158] The Rate Mitigation Plan will come into effect on July 1, 2024, and limits annual Domestic customer rate increases associated with the Muskrat Falls Project and Hydro's operations to 2.25% until 2030. No visibility into rate mitigation or customer rates associated with Muskrat Falls Project or Hydro's costs are provided beyond 2030.[159] The Rate Mitigation Plan requires a $2 billion investment by Hydro to mitigate customer rates over the next six years.

The annual 2.25% customer rate increases stipulated by the Rate Mitigation Plan are largely consistent with the Provincial Government's previously announced plans to mitigate customer rates from the costs of the Muskrat Falls Project.[160] These assumptions were used in the development of the 2025/2026 GRA. As such, the 2025/2026 GRA remains broadly consistent with the recently announced Rate Mitigation Plan.

5.2 NEWFOUNDLAND POWER'S 2025/2026 GRA

Muskrat Falls Project costs and Hydro's costs primarily affect Newfoundland Power's 2025/2026 GRA in two ways. First, assumptions for future customer rate changes are included in

[158] See Government of Newfoundland and Labrador News Release, *Provincial Government Announces Finalization of Rate Mitigation Plan,* Industry, Energy and Technology, May 16, 2024.

[159] See CBC News. *N.L. Hydro to subsidize power rates – to the tune of $2 billion for next 6 years*. Retrieved on May 16, 2024 from https://www.cbc.ca/news/canada/newfoundland-labrador/rate-mitigation-2030-1.7206187.

[160] See the 2025/2026 GRA, *Volume 2: Supporting Materials, Customer, Energy and Demand Forecast*, page 5, footnote 18.

the Company's energy forecast. Second, recovery of Muskrat Falls Project costs and Hydro's costs from Newfoundland Power's customers is considered in the Company's assessment of its business risks.[161]

5.2.1 Energy Forecast

Newfoundland Power filed its *Customer, Energy and Demand Forecast* as part of the 2025/2026 GRA. The *Customer, Energy and Demand Forecast* was reviewed by Brattle and determined to be appropriate for use in the 2025/2026 GRA.[162]

Newfoundland Power's energy sales forecast requires a forecast of future electricity price changes. This is because customer energy sales will be higher or lower depending on the price of electricity in the forecast period.[163]

The Company's forecast of electricity price changes that were used to determine energy sales were based on information known at the time the forecast was developed. This included: (i) a 9.0% customer rate change on July 1, 2024;[164] (ii) a 2.25% customer rate change on July 1, 2025; and (iii) a 2.25% customer rate change on July 1, 2026. The annual 2.25% customer rate changes for July 1, 2025 and July 1, 2026, were based on the Provincial Government's April 2019

---

[161] Muskrat Falls Project costs are also considered in the 2025/2026 GRA, *Volume 2: Supporting Materials, Cost of Capital: Mr. James Coyne, Concentric Energy Advisors, Inc*. Impacts of the Rate Mitigation Plan on this expert evidence will be addressed in rebuttal evidence filed by Concentric.

[162] See *Section 2: Load Forecasting Methodology*.

[163] This is referred to as price elasticity. See the responses to Requests for Information PUB-NP-103 and PUB-NP-159 for additional information.

[164] The 9.0% rate change was based on anticipated rate pressure associated with the annual July 1, 2024 Rate Stabilization Adjustment of 7.5%, as well as a 1.5% increase associated with Newfoundland Power's *2024 Rate of Return on Rate Base Application*.

release, *Protecting You from the Cost Impacts of Muskrat Falls.*[165] The Company's 5.5% proposed increase in customer rates, effective July 1, 2025, was also included in the energy sales forecast under proposed rates.[166]

The current outlook for customer rate changes is largely consistent with the information provided in the Rate Mitigation Plan. The proposed increase in customer rates on July 1, 2024 is anticipated to be in the range of 10.5% to 11%, subject to Hydro's and Newfoundland Power's annual July 1st rate adjustment applications and subsequent orders from the Board.[167] Annual customer rate changes of 2.25% on July 1, 2025 and July 1, 2026, as detailed in the Rate Mitigation Plan, are consistent with the Company's original electricity price forecast. The Company's proposed 5.5% customer rate increase on July 1, 2025, is subject to an order from the Board approving the Company's proposals in its 2025/2026 GRA.

5.2.2 Risk Assessment

Newfoundland Power's business risk assessment in the 2025/2026 GRA includes consideration of Muskrat Falls Project costs and Hydro's costs. The Company's electricity supply outlook continues to be challenged by factors associated with the Muskrat Falls Project. This includes both costs and reliability over the long term.[168] The finalization of the Rate Mitigation Plan

---

165 See the 2025/2026 GRA, *Volume 2: Supporting Materials, Customer, Energy and Demand Forecast*, page 5, footnote 18.

166 See the 2025/2026 GRA, *Volume 2: Supporting Materials, Customer, Energy and Demand Forecast*, Appendix B.

167 The July 1st rate adjustment, including the 2.25% increase associated with the recent provincial government rate mitigation announcement, is estimated to be in the range of 9.0% to 9.5% on July 1, 2024. In addition, Newfoundland Power's *2024 Rate of Return on Rate Base Application* proposes a customer rate increase of 1.5% on July 1, 2024. If Newfoundland Power incorporated a further 2% customer rate increase into its 2024 electricity price forecast (i.e. from 9% to 11%), its 2026 energy sales forecast would be approximately 20 GWh lower due to the effect of price elasticity.

168 See the 2025/2026 GRA, *Volume 1: Application, Company Evidence and Exhibits, 3.3.2 Risk Assessment*, pages 3-30 to 3-34.

provides a level of certainty around customer rate increases due to the Muskrat Falls Project and Hydro for a six-year period starting in 2024. However, it confirms sustained increases in customer rates. The Rate Mitigation Plan does not contemplate rate mitigation or customer rates beyond 2030.

At the time of filling the 2025/2026 GRA, Newfoundland Power recognized cost recovery associated with the Muskrat Falls Project as a risk to the Company. Newfoundland Power also recognized the ongoing efforts of government to mitigate the costs of the Muskrat Falls Project on customer rates.[169]

Newfoundland Power's electricity supply risk is considered by the Company's credit rating agencies, Moody's and DBRS Morningstar ("DBRS"). Moody's has identified "*increased risks of delayed cost recovery as costs associated with Muskrat Falls and related projects add to rate pressure*" as a credit challenge for Newfoundland Power.[170] DBRS also recognized risk associated with the Muskrat Falls Project including reliability concerns associated with the Labrador-Island Link ("LIL") transmission line, which delivers power to the Island Interconnected System from Muskrat Falls.[171] These reliability concerns require the continued operation of Holyrood and construction of additional generating capacity.

Newfoundland Power is required to issue long-term debt to finance its long-life utility assets. For example, in August 2023, the Company issued 30-year First Mortgage Bonds.[172] While the Rate

[169] See the 2025/2026 GRA, *Volume 1: Application, Company Evidence and Exhibits, 3.3.2 Risk Assessment*, page 3-32, lines 1-5, and footnote 67.
[170] See Moody's Investors Service, *Newfoundland Power Inc. – Update to credit analysis,* April 30, 2024, page 2.
[171] See DBRS, *Rating Report – Newfoundland Power Inc.*, October 13, 2023, pages 2-3.
[172] In August 2023, Newfoundland Power issued $90 million in 5.122% Series AS First Mortgage Bonds.

Mitigation Plan provides a level of certainty for the next six years, it does not alleviate long-term risks that an investor in Newfoundland Power's long-term debt would have to consider. Despite the Rate Mitigation Plan, those long-term risks are relatively unchanged since the time the 2025/2026 GRA was filed with the Board.

At the time of Newfoundland Power's 2025/2026 GRA, the Company also recognized that the outlook for electricity supply on the Island Interconnected System changed materially in 2022 with Hydro's latest update to its *Reliability and Resource Adequacy Study*. The change is largely due to lower reliability assumptions related to the LIL.[173] The change in the supply outlook creates significant additional cost pressures on the Island Interconnected System that will coincide with the conclusion of the Rate Mitigation Plan.[174]

5.2.3 Concluding

The recently announced Rate Mitigation Plan is largely consistent with previous announcements from the Provincial Government which were used by Newfoundland Power in the development of the 2025/2026 GRA.

Customer rate changes included in the Rate Mitigation Plan include annual increases of 2.25% in 2025 and 2026. This is consistent with the assumptions used by Newfoundland Power as part of

[173] See Newfoundland Power's 2025/2026 GRA, *Volume 1: Application, Company Evidence and Exhibits, 3.3.2 Risk Assessment*, page 3-30 to 3-34.

[174] For example, Hydro is currently considering the construction of a 154 MW expansion to its Bay d'Espoir hydroelectric facility ("Unit 8") with an estimated cost of $522 million. Hydro is also considering alternative sources of backup generation to replace the 490 MW Holyrood Thermal Generating Station and the 50 MW Hardwoods Gas Turbine. See Newfoundland Power's 2025/2026 GRA, *Section 3.3.2 Risk Assessment*, page 3-32, line 7 to page 3-34, line 13.

its *Customer, Energy and Demand Forecast.* As a result, the *Customer, Energy, and Demand Forecast,* does not need to be adjusted to account for the Rate Mitigation Plan.

The Rate Mitigation Plan provides a level of certainty around customer rate increases due to the Muskrat Falls Project and Hydro in the near term. However, cost pressures associated with the Muskrat Falls Project and future capacity additions continue to contribute to Newfoundland Power's business risk. As a result, the Rate Mitigation Plan does not eliminate the Company's supply risk. These risk factors will continue to be relevant for investors of Newfoundland Power's long-life utility assets.

PREPARED REBUTTAL TESTIMONY:

JAMES M. COYNE AND JOHN P. TROGONOSKI

PREPARED FOR:

NEWFOUNDLAND POWER INC.

BEFORE THE:

NEWFOUNDLAND AND LABRADOR BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

MAY 28, 2024

www.ceadvisors.com

Table of Contents

Table of Figures

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is James M. Coyne, and I am employed by Concentric Energy Advisors, Inc. ("Concentric") as a Senior Vice President. My name is John P. Trogonoski, and I am an Assistant Vice President at Concentric. Our business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752.

Q. Did you also submit a pre-filed expert report in this proceeding?

A. Yes, we submitted evidence on behalf of Newfoundland Power Inc. ("Newfoundland Power" or the "Company") with regard to the appropriate cost of equity and capital structure to the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board").

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of our Rebuttal Testimony is to respond to the evidence submitted on behalf of the Consumer Advocate of the Province of Newfoundland and Labrador ("Consumer Advocate") by Dr. Laurence D. Booth pertaining to the recommended return on equity ("ROE") and capital structure for Newfoundland Power.

II. SUMMARY AND OVERVIEW

Q. Please provide a brief overview of Dr. Booth's Evidence.

A. Dr. Booth recommends an ROE of 7.70 percent for Newfoundland Power, which is 80 basis points ("bps") lower than the Company's current authorized ROE of 8.50 percent, and a reduction in the Company's deemed equity ratio from 45.0 percent to 40.0 percent. Dr. Booth's ROE recommendation is based on a Capital Asset Pricing Model ("CAPM") and Discounted Cash Flow ("DCF") analysis, plus an adjustment of

50 basis points for flotation costs and financial flexibility. Dr. Booth argues that Newfoundland Power is an average risk Canadian utility, and he compares the Company's deemed equity ratio to other Fortis electric utility subsidiaries in Canada. Dr. Booth recommended reduction in the Company's deemed equity ratio from 45.0 percent to 40.0 percent is based on his contention that Newfoundland Power's business risk has decreased since the 2016/2017 General Rate Application ("GRA"), when the Board determined that the deemed common equity ratio for Newfoundland Power should be maintained at 45.0 percent. Lastly, Dr. Booth recommends continued suspension of the Automatic Adjustment Mechanism ("AAM"), although he does suggest that the Board should require Newfoundland Power to present more extensive evidence on the AAM in the next GRA.

Q. Please summarize your response to Dr. Booth's recommended ROE and equity ratio for Newfoundland Power.

A. Dr. Booth's proposed reduction in the authorized ROE for Newfoundland Power from 8.50 percent to 7.70 percent, in conjunction with his proposed reduction in the Company's common equity ratio from 45.0 percent to 40.0 percent, are both individually and collectively lower than any reasonable estimate of Newfoundland Power's cost of capital. Dr. Booth's ROE recommendation fails to reflect the higher interest rate environment as compared to either 2015 or 2021, and several of the inputs to his CAPM and DCF models are based on his own personal judgment rather than current market data. Further, his ROE recommendation would not provide the Company with a return that is comparable to those of other companies with similar business and financial risk. On that basis, Dr. Booth's ROE recommendation does not satisfy the Fair Return Standard.

Q. Are there areas in which you and Dr. Booth are in agreement?

A. Yes. We agree with Dr. Booth that:

- Interest rates on government and utility bonds have increased since the previous GRA, and that interest rates in both Canada and the U.S. are expected to remain near current levels over the next three to five years as persistent inflationary pressure causes central banks in both countries to pursue a more restrictive monetary policy.
- It is important to use more than one methodology to estimate the ROE for Newfoundland Power, although we disagree on certain inputs to the CAPM and DCF models.
- It is reasonable to consider both current and forecast interest rates in the CAPM and Risk Premium analyses and also to consider the results of alternative financial models including the DCF model in estimating the ROE for Newfoundland Power in this proceeding.
- An adjustment of 50 bps for flotation costs and financing flexibility is reasonable and appropriate.
- The AAM should not be reinstated at this time.

Q. What are the primary areas in which you and Dr. Booth disagree with regard to the authorized ROE?

A. Our key areas of disagreement with Dr. Booth are as follows:

- Dr. Booth's CAPM analysis produces an ROE estimate within a range from 7.28 percent to 8.13 percent. His recommended ROE for a benchmark utility of 7.70

percent is at the midpoint of his CAPM analysis. This return is 130 basis points below the lowest authorized ROE for <u>any investor-owned regulated utility in Canada</u> and 160 basis points lower than the average authorized ROE for Canadian investor-owned electric utilities of 9.30 percent. As such, Dr. Booth's ROE recommendation does not meet the comparable return standard.

- Dr. Booth's range of beta estimates has increased to 0.50 to 0.60 from his prior range of 0.45 to 0.55, and he acknowledges that beta coefficients for U.S. electric utility holding companies have increased in recent years. Dr. Booth's beta estimates are based on his personal judgment and fail to reflect current market data. As discussed later in our Rebuttal Testimony (see Figure 5), five-year beta coefficients (both raw and adjusted) for regulated utilities in both Canada and the U.S. have increased substantially since January 2020, when market risk for the utility industry shifted markedly higher compared to historical levels. Dr. Booth's CAPM analysis fails to take into account the increased level of risk for utilities relative to the broader market, and therefore substantially understates the cost of equity for Newfoundland Power. Further, Dr. Booth recommends that betas be adjusted toward the "grand mean" of utility betas rather than following the well-documented empirical evidence that betas below 1.0 systematically understate returns and thus warrant an adjustment towards the market mean of 1.0.[1]

- Dr. Booth's market risk premium ("MRP") of between 5.5 and 6.0 percent is lower than the market risk premium we have relied on of 6.40 percent for Canada and

[1] *See* Marshall E. Blume, On the Assessment of Risk, The Journal of Finance, Vol. XXVI, No. 1 (March 1971) and Marshall E. Blume, Betas And Their Regression Tendencies, The Journal of Finance, Vol. XXX, No. 3 (June 1975), where Blume found that there was strong evidence that Beta regressed toward the market mean, and that tendency was strongest in the case of the lowest risk portfolios.

the U.S. Dr. Booth's MRP is based on historical return data, investor surveys and his own judgment. In addition, we disagree with the method Dr. Booth has used to compute the historical MRP.

- Dr. Booth also presents DCF estimates for the broad equity market in both Canada and the U.S. and for a sample of U.S. electric utilities similar to our U.S. proxy group. He argues that these DCF analyses corroborate the reasonableness of his CAPM results. Several of Dr. Booth's DCF estimates, however, are understated because he relies on historical GDP growth rates and "sustainable" growth rates, both of which understate future utility growth prospects as forecast by knowledgeable equity analysts. Dr. Booth's DCF analysis using projected earnings growth rates for a sample of 13 U.S. electric utilities provides a median return estimate of 8.90 percent, not including an adjustment of 50 basis points for flotation costs and financial flexibility, but he apparently gives these results little weight in arriving at his recommendation based on his CAPM.
- Dividend yields for electric utilities in the DCF model have increased substantially compared to 2021 as utility share prices have declined in response to higher yields on government bonds. Nevertheless, Dr. Booth's DCF analysis continues to produce return estimates similar to those in his report in the 2022/2023 GRA even though dividend yields and the cost of capital have clearly increased for all companies, including electric utilities.
- Dr. Booth contends that the authorized ROE for Newfoundland Power should be substantially lower today than when the Board last determined the Company's ROE in a litigated proceeding in the 2016/2017 GRA. In our view, the relevant point of comparison is the settlement agreement approved by the Board in the

Company's 2022/2023 GRA, which included an authorized ROE of 8.5 percent. Whichever period is used for the comparison, our analysis demonstrates that equity costs have increased as yields on long-term government bonds and A-rated utility bonds have risen substantially in response to stronger economic conditions and higher inflation in both Canada and the U.S.

- Dr. Booth accepts the use of U.S. data but argues that an adjustment is needed to account for differences in risk between Canada and the U.S. While we agree that certain Canadian regulators previously determined that an adjustment for U.S. data was necessary to account for differences in risk between the two countries, the British Columbia Utilities Commission ("BCUC") in its September 2023 decision for FortisBC Energy, Inc. and FortisBC, Inc. relied on North American proxy groups which included U.S. gas and electric utilities, without making an adjustment to U.S. data. Similarly, the Alberta Utilities Commission ("AUC") also relied on a North American proxy group without making an adjustment for U.S. data in its October 2023 decision in the generic cost of capital proceeding. Dr. Booth's views on this matter are based on dated decisions and unsubstantiated by current evidence.
- Dr. Booth essentially dismisses the risks of higher electricity prices on Newfoundland Power's customers, and he argues that the competitive threat for electric utilities such as Newfoundland Power has materially decreased since the 2016/2017 GRA due to Government of Canada policies on carbon reduction, which make alternative fuels such as fuel oil less attractive to customers. We disagree with Dr. Booth's conclusion that Newfoundland Power has lower business risk as a result of decarbonization policies or the ongoing energy

transition. On the contrary, the Federal and Provincial governments' policy objectives have raised uncertainty for investors, while requiring electric utilities to manage a complex array of new challenges while continuing to provide safe and reliable service to customers. In addition, the energy transition requires electric utilities to make substantial capital investments. This highlights the importance of the Board approving an authorized ROE for Newfoundland Power that enables the company to attract capital on reasonable terms to finance the necessary capital investments.

Q. Please summarize Dr. Booth's capital structure recommendation.

A. Dr. Booth recommends a reduction in Newfoundland Power's deemed common equity ratio from 45.0 percent to 40.0 percent, based on his view that the Company's business risk has decreased because it faces less competition from alternative fuels due to decarbonization policies. He contends that Newfoundland Power is a low risk utility that has consistently earned its authorized ROE over the past 30 years.[2] In addition, Dr. Booth asserts that Newfoundland Power would be able to raise capital on reasonable terms with his recommended ROE of 7.70 percent and deemed equity ratio of 40.0 percent.[3]

Q. Which are the primary areas in which you and Dr. Booth disagree regarding the deemed capital structure for Newfoundland Power?

A. The following are our key areas of disagreement with Dr. Booth:

- Dr. Booth's proposed reduction in Newfoundland Power's common equity ratio from 45.0 percent to 40.0 percent is not supported by any persuasive evidence

2 Evidence of Laurence D. Booth, at 96-97.
3 Ibid, at 115-116.

that the Company's business risk has materially changed since the Board's decisions in the 2022/2023 GRA, the 2019/2020 GRA, or the 2016/2017 GRA. Dr. Booth asserts that Newfoundland Power's business risk has decreased due to a reduced competitive threat from alternative fuels, but he provides no persuasive evidence or analysis to support this claim. The fact that Newfoundland Power's electricity rates for residential customers are currently lower than in many other Canadian provinces and U.S. states does not prove that the Company's customers can absorb significant rate increases (i.e., 2.25 percent per year for power supply costs through 2030 under the recently announced rate mitigation plan) without those higher rates affecting their demand for electricity, as Dr. Booth claims.

- We have provided detailed evidence on Canadian and U.S. utilities and on Newfoundland Power which demonstrates that the Company's business risk is similar today to the level at the time of the 2022/2023 GRA. Dr. Booth, on the other hand, has provided neither a detailed risk assessment of other comparable Canadian and U.S. utilities, nor sufficient evidence regarding the change in Newfoundland Power's business or financial risk to support his proposed reduction in the Company's common equity ratio.
- Dr. Booth dismisses the small size of Newfoundland Power as a business risk factor. The Board, however, has consistently found that the risk associated with Newfoundland Power's small size supports a strong common equity ratio. We have shown that Newfoundland Power is smaller than the operating utilities held by the proxy group and that investors and rating agencies consider small size and lack of economic and geographic diversification as important factors in assessing business risk.

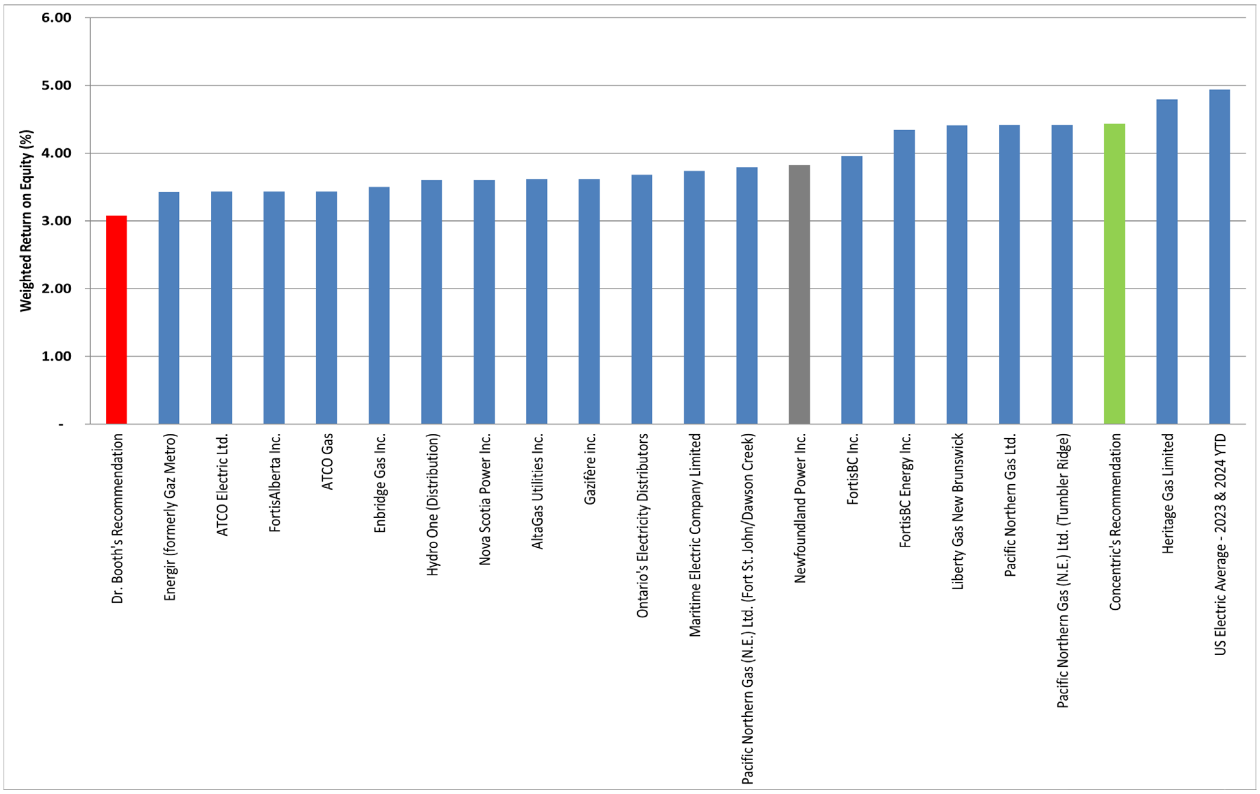
- Dr. Booth presents an analysis that he claims shows that Newfoundland Power's interest coverage ratio is more than sufficient to maintain the Company's 'A' credit rating from Moody's and DBRS Morningstar. However, the Company's Moody's long-term issuer rating is Baa1, two notches lower than its issue rating[4] because the Company provides extra security with issuance of mortgage bonds. Issuance of mortgage bonds is no longer typical for utilities and signals that Newfoundland Power must offer this extra degree of security to elevate its rating and access capital markets on reasonable terms.

Q. Please place Dr. Booth's ROE and capital structure recommendation in the context of other Canadian electric and gas investor-owned utilities.

A. Figure 1 illustrates where Newfoundland Power's weighted ROE (the product of the authorized ROE and the deemed equity ratio) would fall compared to other Canadian investor-owned electric and gas utilities, based on Dr. Booth's ROE and capital structure recommendations. As the Figure shows, the combination of Dr. Booth's recommended 7.7 percent ROE and common equity ratio of 40.0 percent produces a weighted ROE of 3.08 percent for Newfoundland Power. This weighted ROE falls below any Canadian investor-owned electric or gas utility that sets rates through a litigated proceeding. Dr. Booth's cost of capital recommendations, if adopted, would place Newfoundland Power at a significant disadvantage relative to other Canadian investor-owned utilities when raising capital and would not satisfy the Fair Return Standard.

[4] The issuer's credit rating addresses the issuer's overall creditworthiness and usually applies to senior unsecured debt. Issue rating refers to specific financial obligations and considers ranking in the capital structure such as secured or subordinated. Source: Analystprep.com.

Figure 1: Dr. Booth's Recommendation vs. Weighted ROE for Canadian IOUs



Another important consideration is that Newfoundland Power has an Excess Earnings Account that limits the Company's return on rate base, which effectively limits the earned ROE to approximately 40 to 50 basis points above the authorized return for ratemaking purposes. By contrast, Alberta's utilities can earn up to 200 basis points over their allowed return with no customer sharing, between 200 and 400 basis points over their allowed ROE with sharing of 60 percent utility/40 percent customers, and 400 basis points or more over their allowed ROE with sharing of 20 percent utility/80 percent customers.[5] Ontario's electric distributors have a 300

[5] See AUC Decision 27388-D01-2023, 2024-2028 Performance Based Regulation Plan for Alberta Electric and Gas Distribution Utilities, October 4, 2023, at 2.

basis point earnings deadband.[6] Fortis' two BC utilities: FortisBC Energy Inc. ("FEI", the gas utility) and FortisBC Inc. ("FBC", the electric utility) can earn up to 150 basis points over their allowed ROEs; those excess earnings are shared 50/50 with customers. An off-ramp is triggered if achieved earnings deviate from the authorized level by more than 150 basis points, either above or below the authorized ROE.[7] These are important considerations to equity investors. As shown in Figure 2, Newfoundland Power has the lowest weighted ROE among these utilities on this basis.

Figure 2: Weighted Equity Return Based on Upper Bound ROE

Utility	Authorized ROE	Deadband	Upper Bound ROE	Equity Ratio	Upper Bound Weighted ROE
Newfoundland Power	8.50%	0.40% - 0.50%	8.90% - 9.00%	45.0%	4.01% - 4.05%
Alberta Electric Utilities	9.28%[8]	2.00%	11.28%	37.0%	4.17%
Alberta Electric Utilities[9]	9.28%	5.00%	12.68%	37.0%	4.69%
Ontario Electric Utility Distributors	9.21%	3.00%	12.21%	40.0%	4.88%
FortisBC Energy Inc. (gas)	9.65%	1.50%	11.15%	45.0%	5.02%
FortisBC Inc. (electric)	9.65%	1.50%	11.15%	41.0%	4.57%

[6] See Report of the Ontario Energy Board, Renewed Regulatory Framework for Electricity, October 18, 2012, at 13.

[7] See BCUC Orders G-165-20 and G-166-20, June 22, 2020, at ii.

[8] Dr. Booth states that the authorized ROE in Alberta is 9.0%. However, under the AUC formula, the current authorized ROE for electric and gas utilities in Alberta in 2024 is 9.28%.

[9] If an Alberta utility earns 500 basis points over its allowed ROE, it would achieve an Upper Bound ROE of 12.68% calculated as follows: 11.28% in the first tier (200 basis point deadband) plus 1.20% in the second tier (retaining 60% of the next 200 basis points) plus 0.20% in the third tier (retaining 20% of the next 100 basis points).

Q. How is the remainder of your Rebuttal Testimony organized?

A. In Section III, we discuss changes in capital market conditions since the filing of our Report and as compared to conditions at the time of the 2016/2017 GRA; in Section IV, we respond to Dr. Booth's concerns regarding the use of U.S. companies in a North American proxy group to estimate the cost of equity for a Canadian regulated utility; in Section V, we discuss where we diverge with Dr. Booth on the models used to estimate the ROE, including reasonable inputs for the CAPM and DCF models; in Section VI, we discuss our differences with Dr. Booth regarding the relative risk of Newfoundland Power as compared to other investor-owned electric utilities in Canada and the U.S., and with his recommendation to reduce the common equity component of Newfoundland Power's capital structure. Finally, in Section VII we affirm our ROE and capital structure recommendations.

III. CAPITAL MARKET CONDITIONS

Q. Dr. Booth quotes the Supreme Court of Canada's *Northwestern* decision in a few instances.[10] Do you agree with his interpretation of that decision, and has he followed its most fundamental guidance?

A. No, on both points. We take issue with his interpretation of the decision and his failure to adhere to its most fundamental guidance. Dr. Booth seems to suggest that investors should ignore authorized returns in other jurisdictions as a basis for assessing comparability of return. While not offering a legal opinion, our experience is that investors do focus on authorized returns in other jurisdictions as a benchmark

10 *See*, for example, Evidence of Laurence D. Booth, at 6-7.

for formulating their return expectations. Further, Dr. Booth ignores the full language of *Northwestern* that provides a regulator with considerable latitude in terms of what evidence is required to reach its determination of a fair return. Perhaps most on point, Justice Smith writes in the *Northwestern* decision:

> *[T]he question of a fair rate of return is largely one of opinion, hardly capable of being reduced to certainty by evidence, and appears to be one of the things entrusted by the statute to the judgment of the Board.*

Nothing in this passage suggests that a regulator should not consider authorized returns in other jurisdictions.

Dr. Booth also states that the authorized ROE should be set in the context of conditions in the economy and capital markets,[11] and we agree. He acknowledges that the inflation and government bond yields have risen significantly following the fiscal and monetary stimulus provided by governments and central banks in response to the COVID pandemic. He also recognizes that risk and betas are constantly changing for companies and industries, yet he continues to use the same beta coefficients for regulated utilities even though current market data indicate that investment risk has increased for the utility sector relative to the broad market.

Dr. Booth devotes many pages of his evidence to discussing economic and capital market conditions. Nevertheless, despite changes in interest rates, credit spreads, the outlook for inflation, the stage of the business cycle, market volatility, differing utility risk profiles and growth prospects, Dr. Booth's ROE recommendation for a benchmark utility in Canada has unwaveringly ranged from 7.50 to 7.70 percent over the past decade. All of the above factors affect the cost of capital. We are not aware

[11] Ibid, at 8.

of any Canadian regulator that has authorized any investor-owned Canadian electric or gas distributor an ROE as low as 7.70 percent since at least 2000.

Q. How have capital market conditions changed since Newfoundland Power's previous GRA filings?

A. We updated the bond yields and inflation data shown in Figure 3 of our Report to include market data as of April 30, 2024. We also added a column to allow for comparisons to the Company's 2016/2017 GRA, which Dr. Booth asserts is the appropriate point of comparison since that is the last time the Board determined the authorized ROE and capital structure for Newfoundland Power in a fully litigated proceeding. Figure 3 below shows that interest rates on Canadian government and utility bonds are substantially higher as of April 2024 than at the time of the analysis in the 2022/2023 GRA (when Newfoundland Power's authorized ROE was last approved by the Board as part of a settlement agreement) or in August 2015 (when the ROE analysis in the 2016/2017 GRA was conducted by Mr. Coyne).

Figure 3: Comparison of Key Interest Rates and Inflation Data

Indicator	August 2015	March 2021	August 2023	April 2024
Bank of Canada Overnight Rate	0.50%	0.25%	5.00%	5.00%
10-year Government of Canada bond	1.58%	1.50%	3.65%	3.70%
30-year Government of Canada bond	2.24%	1.94%	3.50%	3.60%
A-rated Canadian utility bond[12]	3.89%	3.24%	4.99%	4.96%
Consumer Price Inflation – Canada	1.3%	2.2%	4.0%	2.9%

Notably, 10-year Canadian government bond yields have increased by 212 basis points since August 2015 and by 220 basis points since March 2021, while 30-year Canadian government bond yields have increased by 136 basis points since August 2015 and 166 basis points since March 2021. Similarly, A-rated Canadian utility bond yields have increased by 107 basis points since August 2015 and by 172 basis points since March 2021. Consumer prices have also risen at a much faster pace in 2023 and 2024 compared to at the time of the 2016/2017 GRA or the 2022/2023 GRA. Despite substantially higher government bond yields and higher inflation, both of which are market indicators of capital costs, Dr. Booth's ROE recommendation for Newfoundland Power has only increased by 20 basis points, from 7.50 percent to 7.70 percent.

12 Source: Bloomberg Professional; BVCAUA30 BVLI Index (Canadian Utility A+, A, and A- BVAL 30-year Yield Curve). Replaces the C29530Y Index, which was discontinued on February 2, 2024.

IV. PROXY GROUP

Q. What is Dr. Booth's position regarding the use of U.S. companies to set the authorized return for a Canadian utility?

A. Dr. Booth recognizes that the number of publicly-traded utilities in Canada has continued to shrink the past decade due to industry consolidation. Despite this constraint, Dr. Booth argues that if U.S. companies and data are going to be used to set the authorized return for a Canadian utility, the U.S. data must be adjusted to account for differences in relative risk between Canada and the U.S.[13] He cites the Order No. P.U.43 (2009) in which the Board accepted the use of U.S. data but made an adjustment of 50-100 basis points for differences in risk between the two countries. This same decision was reached in the Board's 2016 decision for Newfoundland Power. He also quotes 2009 decisions of the BCUC and the Regie in Quebec while ignoring more recent decisions in British Columbia and Alberta that accept the use of a North American proxy group without adjusting U.S. data. Dr. Booth states that he is "not aware of any decision that has explicitly taken estimates from U.S. companies or U.S. capital markets and said that they are appropriate for use in Canada without any adjustment."[14]

Q. Please discuss the recent regulatory precedent in Canada.

A. Both the BCUC and the AUC have recently accepted the use of a North American proxy group comprised of utility companies in both Canada and the U.S. to set the authorized ROE for utilities under their jurisdiction without making an adjustment to

13 Evidence of Laurence D. Booth, at 75-89.
14 Ibid, at 85.

the U.S. data. Specifically, the BCUC explained its rationale for using a North American proxy group as follows:

> *For the reasons outlined above, we find the use of the Canadian proxy groups and US proxy groups alone to be inferior to that of using a North American proxy group which has a reasonable mix of both Canadian and US comparators, and the averaging of the results of these three groups to be a poor compromise. 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.*[15]

The recent BCUC decision is consistent with our view that equity investors and credit analysts consider the utility industry as a North American industry, with Canadian companies competing for capital with similar risk companies in both countries. The AUC also relied on a North American proxy group of electric and gas utilities to set the generic ROEs for utilities in Alberta without adjusting U.S. input data. Dr. Booth's continued assertion the U.S. data must be adjusted downward due to differences in risk relative to Canada is out of step with recent regulatory policy on this issue, as regulators have come to recognize that the capital markets and economies of Canada and the U.S. are highly integrated and are competing for capital from the same pool of investors.

Q. Does Dr. Booth have any additional objections to the use of U.S. companies or U.S. data?

A. Yes. Dr. Booth contends that even though the principles of regulation are similar in the U.S. as in Canada, their interpretation or application are different. He argues that Canada is more conservative and applies regulation more stringently than in the U.S.,

[15] British Columbia Utilities Commission, Decision and Order G-236-23, September 5, 2023, at 16.

and he cites the U.S. banking and telecom industries as examples of how U.S. regulation leads to greater risk for investors.[16]

Q. Do you agree with Dr. Booth's position on this issue?

A. No, we do not. The risk assessment presented in our Report shows that Newfoundland Power has similar risk mitigating mechanisms as electric utilities in our North American proxy group.[17] The biggest difference between Canada and the U.S. in terms of utility regulation is the gap in the deemed equity ratio for utilities in Canada compared to those in the U.S., as we discuss in more detail in the section on business risk and capital structure.

Dr. Booth references a September 2013 Moody's report in which the rating agency reversed its views in the 2005 and 2009 reports and found that the regulatory environment in the U.S. had improved significantly due primarily to the increased prevalence of cost recovery mechanisms and the corresponding reduction in regulatory lag. Dr. Booth essentially dismisses the importance of the 2013 Moody's report even though it directly states that the 2013 report supersedes the 2009 report and demonstrates that Moody's changed its view of U.S. utility regulation over ten years ago. Dr. Booth continues to cling to outdated reports that better support his viewpoint, even though the regulatory landscape in the U.S. has changed relative to Canada.

Equity analysts have reached similar conclusions to the credit analysts at Moody's. For example, a March 2019 report by Scotiabank indicated that they view the regulatory environments in Canada and the U.S. as being similar for regulated

16 Evidence of Laurence D. Booth, at 75 and 79.
17 Concentric Cost of Capital Report, Volume 2, at 78 and 80-82.

utilities. In explaining why they expect the valuations of Canadian and U.S. utilities to converge, Scotiabank observed:

> *Historically, the Canadian utilities have traded at a discount to their mid-cap peers. We attribute this to the historical view that Canadian regulation was superior to U.S. regulation (<u>we no longer have that view</u>) as well as to strong earnings growth in part due to M&A.*[18] *(emphasis added)*

Q. Please summarize your conclusions on the use of a North American proxy group to set the authorized ROE for Newfoundland Power.

A. While we recognize that previous decisions in Canada have made a 0.50-1.0 percent downward adjustment for estimates derived from U.S. utility proxy groups, there is more recent regulatory precedent in Canada for the use of a North American proxy group to set the return for Canadian regulated utilities without making an adjustment to U.S. return data. For all of the reasons stated above and in our Report, we believe it is appropriate to use U.S. data without making an adjustment for differences between Canada and the U.S., because no such adjustment can be justified on a relative risk basis. Our ROE recommendation for Newfoundland Power is based on the average model results for a North American proxy group of electric utilities, using a combination of Canadian and U.S. market data consistent with recent decisions of the BCUC and AUC.

Further, in our firm's work for Canadian companies assessing investments in U.S. utility companies, they do not apply a risk premium to U.S. companies nor are they willing to invest equity capital at the types of returns recommended by Dr. Booth. As broadly acknowledged in the application of cost of capital to regulated utilities,

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

similar and comparable are the standards, not exactly the same. In other words, it is not necessary to conclude that a utility such as Newfoundland Power is exactly identical to the proxy companies for purposes of determining the cost of capital, only that they are similar or comparable.

Q. Dr. Booth also comments on the generation ownership of your U.S. Electric proxy group.[19] What is your response?

A. Dr. Booth observes that all companies in our U.S. Electric proxy group are vertically-integrated electric utilities except for Eversource Energy. He notes that in our 2013 evidence for Hydro Quebec Distribution and Hydro Quebec Transmission, we found that there was a difference in authorized ROEs for integrated electric utilities as compared with T&D only companies. He also observes that six of the ten companies in our U.S. Electric proxy group own a significant amount of nuclear generation, which he asserts is higher risk.

In response to Dr. Booth's comments on generation ownership, we did not deliberately screen our U.S. Electric proxy group to only include companies that own regulated generation. Rather, none of the T&D utilities in the Value Line universe pass all of our stated screening criteria.[20] As explained in our response to PUB-NP-110, we included Eversource Energy in our U.S. Electric and North American Electric proxy groups, even though they do not meet the percentage of operating income from electric utility service. The AUC recently rejected concerns from intervenors about generation ownership being higher risk when it stated: "The Commission is not

[19] Evidence of Laurence D. Booth, at 102-104.

[20] The T&D utilities generally fail to pass our screens for percentage of regulated operating income and percentage of operating income from electric utility operations.

persuaded by the argument that certain of the representative utilities in the comparator group lack comparability due to the involvement of their parent corporations in generation, retail or other unregulated business sectors."[21] We agree with the AUC that integrated electric utilities can be included in the proxy group for a company such as Newfoundland Power without making a downward adjustment to the authorized ROE. The same AUC decision also included companies that own nuclear generation in the North American proxy group without making a downward adjustment to the returns estimates for those companies. This is also consistent with FERC's approach to setting ROEs for regulated transmission companies (with no generation or distribution) using a broad sample of vertically integrated electric utilities.

V. ROE ESTIMATION MODELS

A. Use of Multiple Methodologies

Q. Is there academic support for the use of multiple methodologies to estimate the cost of equity?

A. Yes, there is. For example, in their college level finance text, Professors Eugene Brigham and Louis Gapenski discuss the value of using more than one model to estimate the cost of equity. They conclude:

> *"In practical work, it is often best to use all three methods – CAPM, bond yield plus risk premium, and DCF – and then apply judgment when the methods produce different results. People experienced in estimating equity capital costs recognize that both careful analysis and some very fine judgments are required."*[22]

[21] Alberta Utilities Commission, Decision 27084-D02-2023, October 9, 2023, at para. 102.

[22] Eugene F. Brigham and Louis C. Gapenski, Financial Management Theory and Practice, Fourth Edition, at 256.

Q. What models have Concentric and Dr. Booth used to estimate the authorized ROE for Newfoundland Power?

A. As discussed in our Report, our ROE recommendation for Newfoundland Power is based on the average results of three models: 1) the CAPM using a historical market risk premium; 2) the multi-stage DCF model; and 3) the Risk Premium approach. Dr. Booth, on the other hand, relies primarily on the results of his CAPM analysis to estimate the ROE for Newfoundland Power, and he uses the DCF model to test the reasonableness of his CAPM results.

Q. How does Dr. Booth's primary reliance on the CAPM results undermine his ability to provide a fair return estimate?

A. It is generally well-accepted among cost of capital practitioners and regulatory commissions that multiple methods for estimating the fair rate of return provide the best basis upon which to make a fair determination. Specifically, the OEB, when confronted with this issue in its Consultative Cost of Capital Process, stated:

> *The Board agrees that the use of multiple tests to directly and indirectly estimate the ERP is a superior approach to informing its judgment than reliance on a single methodology. In particular, the Board is concerned that CAPM, as applied by Dr. Booth, does not adequately capture the inverse relationship between the ERP and the long Canada bond yield. As such, the Board does not accept the recommendation that it place overwhelming weight on a CAPM estimate in the determination of the initial ERP.*[23]

In recent decisions, the BCUC and AUC have relied on the results of multiple methods to set the authorized ROE for regulated utilities under their jurisdiction. In particular, the BCUC relied on the average results of the multi-stage DCF model, the CAPM, and

[23] Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (December 11, 2009), pp. 36-37.

the Risk Premium approach, while the AUC considered the results of the constant growth and multi-stage forms of the DCF model and the CAPM.[24] Because each model has strengths and limitations, it is reasonable to consider multiple methodologies to estimate the ROE. Placing primary reliance on one particular model can lead to ROE estimates that fail to reflect all relevant information that investors consider.

B. CAPM Analysis

Q. Please summarize Dr. Booth's CAPM analysis and results.

A. Dr. Booth's CAPM analysis is based on a forecasted long Canada bond yield of 3.80 percent, an equity risk premium between 5.50 percent and 6.00 percent, and Beta coefficients from 0.50 to 0.60. Dr. Booth then applies a credit spread adjustment of 23 basis points to the risk-free rate and adds 50 basis points to his CAPM results for flotation costs and financial flexibility. Dr. Booth's CAPM estimate ranges from 7.28 percent to 8.13 percent, with an approximate midpoint of 7.70 percent.[25] This return estimate is 160 basis points lower than average authorized ROE for investor-owned electric utilities in Canada of 9.30 percent and 130 basis points lower than the authorized ROE of any investor-owned utility in Canada.

Q. Dr. Booth states that the CAPM is "overwhelmingly the most important model used by a company in estimating their cost of equity capital."[26] Do you agree?

A. No, we do not agree in the context of setting a regulated rate of return. Dr. Booth places primary reliance for this statement on a paper published in 2001 by Graham and Harvey. He also cites a 2011 article published by Baker, et. al. that surveyed small

24 British Columbia Utilities Commission, Decision and Order G-236-23, September 5, 2023, at 135-136, and Alberta Utilities Commission, Decision 27084-D02-2023, October 9, 2023, at para. 170-172.
25 Evidence of Laurence D. Booth, at 49.
26 Ibid, at 38.

and large firms in Canada on this same question. Based on our review of the Graham and Harvey paper, it was written from the perspective of capital budgeting and for establishing discount rates for target investments. While we agree that the CAPM is used for this purpose because it is simple to use for corporate analysts, we see little parallel between establishing a discount rate for capital budgeting purposes (i.e., a project hurdle rate) and determining the investor required return for purposes of utility regulation. In addition, the Graham and Harvey paper (2001) preceded the financial crisis and the prolonged period of unusually low interest rates that followed. We question whether the conclusions of this paper can reasonably be extrapolated to the present. Neither article sheds any light on the extent to which the CAPM is used to set the regulatory rate of return in utility rate proceedings.

Q. When reasonable inputs are used, does the CAPM produce reliable estimates of the authorized ROE for regulated utilities such as Newfoundland Power?

A. Yes.

Q. How do Concentric's CAPM inputs compare to Dr. Booth's application of the model?

A. Both Concentric and Dr. Booth use a forecast of the government bond yield as the risk-free rate in the CAPM analysis, and we both use a historical market risk premium. For example, Dr. Booth uses a risk-free rate of 4.03 percent based on his forecast of the Canadian long government bond yield of 3.80 percent plus an adjustment for credit risk of 23 basis points. By comparison, Concentric uses a risk-free rate of 3.52 percent for Canadian companies and 3.98 percent for U.S. companies) based on projected government bond yields from Consensus Economics plus the long-term average historical spread between 10- and 30-year government bonds.[27] Dr. Booth uses a market risk premium of 5.50 to 6.00 percent, based on the historical market risk premium in Canada and the U.S. and investor surveys published by Dr. Pablo Fernandez. Concentric also uses historical market return data published by Kroll to establish the average market risk premium for Canada and the U.S. of 6.40 percent.

Q. Do you agree with Dr. Booth's estimate of the MRP?

A. We agree with the use of the historical MRP under current market conditions because interest rates in both Canada and the U.S. are approaching historical average levels used to calculate the historical MRP. However, unlike Dr. Booth, we use the average historical MRP for Canada and the U.S., which averages approximately 6.40 percent, and we use the income only return on government bonds instead of the total return. As we explained in the response to CA-NP-220, Kroll calculates the historical MRP based on the total return on large company stocks less the income-only return on government bonds.

Q. Please discuss the Fernandez investor survey which Dr. Booth uses to evaluate the reasonableness of the historical MRP.

A. The 2023 Fernandez survey cited by Dr. Booth is an email survey sent in March 2023 to more than 15,000 email addresses of finance and economics professors, analysts and managers of companies. Fernandez received 1,717 reportable responses with respect to the MRP for 80 countries. Respondents were asked about the risk-free rate and the MRP used to calculate the required return on equity in different countries. Although the Fernandez survey provides information on the number and range of

[27] Concentric Cost of Capital Report, Volume 2, at 43.

responses concerning the level of the MRP for each country, it is not clear from the survey how the respondents derived the MRP in their response (e.g., the source for their information), nor does the survey establish for what purpose the respondents applied the MRP estimate. For Canada, the survey received 41 responses with a mean of 6.0 percent, a median of 6.0 percent, a maximum of 8.0 percent and a minimum of 4.0 percent. The Fernandez survey no longer reports the standard deviation of the responses. In our view, the wide range of survey responses from 4.0 percent to 8.0 percent illustrates both the importance of alternate measures of the MRP and the general level of uncertainty regarding future returns.

Q. Dr. Booth attempts to justify the reasonableness of his MRP estimate by comparison to market return estimates from various investment banks. How do these projected equity returns compare to the actual returns realized by investors?

A. Dr. Booth cites several reports from several investment firms including a July 2019 report from TD Economics that projects the total return for the S&P 500 as 5.5 percent for the period from 2019-2028, within a range from 4.0 percent to 7.0 percent.[28] While Dr. Booth likes to argue that investors are overly optimistic, this TD Economics report demonstrates that investors can also be overly pessimistic. As shown in Figure 4 below, the actual annual returns for the S&P 500 Index for the period from 2019-2023 were as follows:

Figure 4: S&P 500 Total Returns – 2019-2023

	S&P total return
2019	31.49%
2020	18.40%
2021	28.71%

[28] Evidence of Laurence D. Booth, at 59.

2022	(18.11%)
2023	26.29%

These annual total returns for the S&P 500 suggest that the expected returns in TD Economics' 2019 report were substantially understated, and that market risk premiums based on these types of projections would be similarly understated.

Q. Is your recommended ROE for Newfoundland Power based in part on a CAPM analysis that uses a forward-looking MRP?

A. No, our CAPM analysis for Newfoundland Power in this proceeding is based on a historical MRP. This highlights the conservative nature of our CAPM analysis, because current government bond yields still remain lower than long-term historical averages, suggesting that the MRP should be higher than the long-term historical values that were used in our analysis. In the U.S., we observe that FERC continues to rely on a CAPM analysis that uses a forward-looking MRP based on the same methodology Concentric has used in prior testimony for Newfoundland Power and other U.S. and Canadian electric and gas utilities.

Q. What is your most important area of disagreement with Dr. Booth's CAPM analysis?

A. The most important area of divergence in our respective CAPM analyses is with respect to beta. This is what drives the unreasonably low return estimate that Dr. Booth uses to support his ROE recommendation for Newfoundland Power.

Q. Please explain the disagreement over beta in the CAPM analysis.

A. Dr. Booth uses a range of beta coefficients from 0.50 to 0.60 for regulated utilities based on his judgment that utilities are low risk companies that investors value for their stability and dividend payments during economic downturns. Although Dr.

Booth has increased his range for beta in recognition that betas have increased in recent years for electric utilities, his estimated beta coefficients are not based on current market data for companies that are comparable in risk to Newfoundland Power. On the other hand, as described in our Report, Concentric uses five-year weekly betas from Bloomberg and Value Line for our Canadian and U.S. proxy group companies.[29] Bloomberg and Value Line betas for these companies have increased since January 2020 to approximately 0.90, which is substantially higher than the long-term historical average of 0.60 to 0.70.[30] This is evidence that equity investors no longer perceive utilities as safe havens during economic downturns or periods of market distress. Rather, these companies are trading more like the broad market, and thus no longer provide the diversification benefits referenced by Dr. Booth.

Q. Dr. Booth devotes many pages of his report to explaining why he disagrees with the widely-accepted adjustment methodology employed by most providers of beta for financial analysis, which is to adjust utility betas toward the market average of 1.0.[31] Please comment.

A. While we continue to support the use of Blume adjusted betas, the debate is less relevant under current market conditions because even unadjusted or "raw" betas for utilities are much higher than those used in Dr. Booth's CAPM analysis. Figure 5 below shows both the raw and Blume adjusted betas for the companies in Concentric's Canadian, U.S. Electric, and North American proxy groups. As the data in the table demonstrate, both raw and Blume adjusted betas are significantly higher than Dr. Booth's estimates of 0.50 to 0.60.

[29] Concentric Cost of Capital Report, Volume 2, at 44.
[30] See Figure 5 of this Rebuttal Testimony.
[31] Evidence of Laurence D. Booth, at 44-45 and Appendix C.

Figure 5: Comparison of Beta Coefficients

Five-Year Bloomberg Betas	January 2020	March 2021	August 2023	April 2024
Canadian – Raw	0.71	0.85	0.81	0.85
Canadian – Blume-Adj.	0.81	0.90	0.87	0.90
U.S. Electric – Raw	0.31	0.85	0.83	0.85
U.S. Electric – Blume-Adj.	0.54	0.90	0.89	0.90
North American – Raw	0.38	0.81	0.79	0.82
North American – Blume-Adj.	0.59	0.88	0.86	0.88

Q. Are you aware of any Canadian regulators that have recently addressed the use of Blume adjusted betas for regulated utilities?

A. Yes. In the recent cost of capital proceeding for FortisBC in British Columbia, the BCUC retained a consultant, Dr. Jonathan Lesser, to advise the BCUC on the appropriate ROE methodologies and inputs for regulated utilities. Dr. Lesser submitted his report in August 2021. With regard to the question of what beta should be used in the CAPM analysis, Dr. Lesser notes: "One potential problem with using raw beta values – in addition to determining the appropriate time period, data frequency, and so forth – is that estimating the allowed ROE for a utility is a forward-looking exercise."[32] For that reason, Dr. Lesser supported the use of adjusted betas:

> *Because regulators establishing the allowed ROE for a regulated utility are basing that allowed ROE on expected market conditions over an indefinite future, adjusted beta values are typically considered to be more*

32 Dr. Jonathan A. Lesser, Regulated Utility Cost of Capital: Theory and Canadian Practice, August 4, 2021, at 42.

> *appropriate when applying the CAPM. One reason is that estimated raw beta values can be negative.*[33]

The BCUC noted in its September 2023 Decision and Order that it had not previously accepted the use of Blume adjusted betas. However, the BCUC reversed its previous decisions on this issue, stating:

> *However, 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.*[34]

In addition, Concentric submitted a full cost of capital analysis in the consultation on Cost of Capital conducted by the OEB in 2009 that led to a reset of the ROE and the current formula for Ontario's gas and electric distributors and transmitters. Concentric's CAPM analysis included the standard Blume adjusted betas from Bloomberg and Value Line, just as we have utilized in this proceeding. In its decision, the OEB took no issue with Concentric's use of betas adjusted toward the market mean of 1.0.

Q. Please detail your concern with Dr. Booth's use of betas that are based on his personal judgment rather than actual market data.

A. Rather than relying on actual market data that is available to investors, Dr. Booth prefers to employ betas within a range from 0.50 to 0.60 based on his own personal judgment. The importance of using current market data has been highlighted since February 2020, when beta coefficients reported by Value Line and Bloomberg have

33 Ibid.
34 British Columbia Utilities Commission, Decision and Order G-236-23, September 5, 2023, at 75.

increased substantially for regulated utilities because those companies have traded more like the broader market. It is inappropriate to use personal judgment when market data is available, and this is especially important when the fundamental relationship between the utility industry and the broader market has changed to the extent it has in recent years.

Q. Do the results of Dr. Booth's CAPM analysis adequately reflect current market conditions?

A. No, they do not. While Dr. Booth has used a projected risk-free rate of 3.80 percent to which he adds 23 basis points for his credit risk adjustment, his historical MRP of 5.50 to 6.00 percent is understated, and his judgment-based estimate of betas for Canadian regulated utilities generally are well below current market data for companies with similar risk as Newfoundland Power. By continuing to rely on his own personal judgment, especially with respect to beta, instead of current capital market data, Dr. Booth's CAPM results substantially understate the cost of equity for electric utilities such as Newfoundland Power. Given that there has not been an authorized ROE for a Canadian investor-owned electric or gas utility below 8.30 percent since at least 2000, it would be reasonable for Dr. Booth to question the inputs and assumptions of his CAPM analysis and to place more weight on alternative methodologies to estimate the ROE.

C. DCF analysis

Q. Please describe Dr. Booth's DCF analyses.

A. Dr. Booth refers to the DCF model as "the basic method used for valuing bonds by professional investors and corporate executives."[35] On pages 9-10 of Appendix D to his Evidence, Dr. Booth performs two DCF calculations for the broad Canadian market. The first is based on historic GDP growth from 1961-2023 of 3.03 percent and the Bank of Canada's operating band for inflation of 2.00 percent to derive an average growth rate of 5.1 percent. He then multiplies this growth rate by the dividend yield on the TSX Index at the end of December 2020 of 3.15 percent to arrive at a DCF estimate of 8.41 percent. His second DCF analysis for the Canadian market uses the median dividend payout ratio of corporate Canada since 1956 of 52 percent and the median earned ROE for Corporate Canada of 9.97 percent, which produces a "sustainable growth rate" of 4.79 percent and a DCF return estimate of 8.10 percent. On pages 11-12 of Appendix D, Dr. Booth performs a similar analysis on the S&P 500 in the U.S. using sustainable growth rates and median dividend payout ratios and arrives at an equity cost estimate of 9.6 percent.

Dr. Booth also performs a DCF analysis on a group of 13 U.S. electric utilities based on forecast earnings growth rates and sustainable growth rates. As shown in Schedule 13 of Appendix D, Dr. Booth's DCF analysis of a U.S. electric group produces ROE estimates of 8.84 percent (mean) and 8.90 percent (median) using EPS growth and 6.75 percent (mean) and 6.87 percent (median) using sustainable growth rates. These DCF estimates do not include an adjustment for flotation costs and financial flexibility. If flotation costs of 50 bps were added to the DCF results for the U.S.

[35] Evidence of Laurence D. Booth, at 50.

electric utilities in Schedule 13, the ROE estimates would be 9.34 percent (mean) and 9.40 percent (median) using EPS growth rates.

Q. Please comment on the results of Dr. Booth's various DCF analyses.

A. The mean results produced by Dr. Booth's DCF analysis using forecast EPS growth rates for a sample of U.S. electric utilities (as shown in Schedule 13) are similar to those in our Report, if we were to add 50 basis points for flotation costs to his DCF results. The other DCF analyses provided by Dr. Booth are based on historical economic growth rates for Canada and the U.S. and do not provide a forward-looking estimate of the cost of equity for the utility industry generally or Newfoundland Power in particular. It is not reasonable to estimate the ROE for Newfoundland Power based on historical GDP growth in Canada plus a current dividend yield because this does not reflect the specific business and financial risk that the Company faces in raising equity capital. In summary, Dr. Booth's historical economic data and sustainable growth rates shed little light on the forward-looking cost of equity for Newfoundland Power.

Q. Please summarize Dr. Booth's position regarding earnings growth rates in the DCF model.

A. Dr. Booth argues that DCF estimates for individual companies are not as reliable as for the broad market, that analyst's earnings growth rates are biased high, and he suggests that utility growth rates are constrained or capped by GDP growth over the long run.[36]

[36] Evidence of Laurence D. Booth, at 52-53.

Q. Do you share Dr. Booth's concern that analysts' projected EPS growth rates are biased upwards?

A. No, we do not. Figure 22 on page 38 of our Report demonstrates that the projected EPS growth rates for the companies in our Canadian proxy group are lower than the historical EPS and DPS growth rates for these same companies over the past 15 years. Further, on average, the projected EPS growth rate for all three proxy groups of 5.37 percent is lower than the average historical EPS and DPS growth rates of 5.87 percent and 6.50 percent, respectively, for these proxy companies. In addition, historical and projected EPS growth rates are higher than projected GDP growth, demonstrating that GDP does not serve as a cap on earnings growth for regulated utilities. Based on that analysis, we disagree with Dr. Booth. Nevertheless, our ROE recommendation for Newfoundland Power is not based on the results of the Constant Growth DCF model.

Q. What form of the DCF model did Concentric use to estimate the ROE for Newfoundland Power in this proceeding?

A. Although we see no reason to question the analyst growth rate estimates used in the Constant Growth DCF analysis, our ROE recommendation considers the results of the Multi-Stage DCF analysis, which mitigates questions around "analyst bias" or concerns about whether the analyst growth rate could be sustained in perpetuity as suggested by Dr. Booth. Our Multi-Stage DCF model uses analyst growth rates for the first 5 years of the model, while the remaining years reflect projected GDP growth or the transition to GDP growth.

Q. Have other Canadian regulators considered the results of the DCF model to establish the authorized ROE for utilities under their jurisdiction?

A. Yes. While Dr. Booth contends that the DCF model fell out of favor with utility regulators in the mid-1990s,[37] there is simply no basis for this assertion. Several Canadian regulators have considered the results of the DCF model along with the CAPM to establish authorized returns for regulated electric and gas utilities. For example, utility regulators in Alberta, British Columbia, and Ontario have considered the results of the DCF model along with other models to set the authorized ROE for electric and gas utilities under their jurisdiction. Specifically, the AUC considered the results of the constant growth and multi-stage forms of the DCF model and the CAPM in its October 2023 decision setting the generic ROE for Alberta's electric and gas utilities,[38] the BCUC relied on the average results of the multi-stage DCF model, the CAPM, and the Risk Premium analysis in its September 2023 Decision and Order involving FortisBC Energy, Inc. and FortisBC, Inc.,[39] and the Ontario Energy Board ("OEB") considered the results of the DCF model in its 2009 Generic Cost of Capital decision.[40]

[37] Evidence of Laurence D. Booth, at 54.
[38] Alberta Utilities Commission, Decision 27084-D02-2023, October 9, 2023, at para. 170-172.
[39] British Columbia Utilities Commission, Decision and Order G-236-23, September 5, 2023, at 135-136.
[40] Ontario Energy Board, 2009 Generic Cost of Capital, Decision EB-2009-0084, issued December 11, 2009, at 36 and 63.

Q. Dr. Booth calculates a DCF estimate for a sample of 13 U.S. electric utilities.[41] Do you agree that sustainable growth rates appropriately capture the expected growth of a regulated utility?

A. Not as calculated by Dr. Booth. The full form of the "sustainable growth" model is premised on the idea that a firm's growth is a function of its expected earnings, and the extent to which it retains earnings to re-invest in the enterprise. In the sustainable growth formula, this is commonly referred to as the product of "b x r", where "b" is the retention ratio, or the portion of net income not paid in dividends, and "r" is the expected ROE on the portion of net income that is retained within the company as a means for future growth. In the fullest form of the sustainable growth formula, new equity issuances, or what are commonly known as externally generated funds, are also considered. This is shown as the product of "s x v", where "s" represents the growth in shares outstanding, and "v" is that portion of the market/book ratio that exceeds unity. This methodology is recognized as a common approach to calculating the sustainable growth rate.

Dr. Booth has relied upon the simplest form of the sustainable growth model, projecting growth only as a function of internally generated funds. The "b x r" method fails to account for future equity issuances, and no sustainable growth formula considers debt leverage as a source of future growth for an entity. Failure to consider the potential for debt and equity issuances as a source of future growth understates the firm's growth potential under this model.

41 Evidence of Laurence D. Booth, Appendix D, Schedule 13.

Q. Have other regulators rejected the use of sustainable growth rates?

A. Yes. We are not aware of any Canadian regulatory jurisdiction that uses sustainable growth rates in the DCF model. The BCUC explicitly rejected Dr. Booth's use of sustainable growth rates in 2016, stating: "Therefore, the Panel finds that no weight can be placed on Dr. Booth's sustainable growth rate model for the US proxy group as it is not based on a more robust and comprehensive version of this model."[42] In the U.S., FERC moved away from its use of sustainable growth rates in its DCF methodology to be applied in public utility rate cases in 2014.[43] In summary, FERC adopted the same two-step DCF methodology it has employed in gas and oil pipeline rate proceedings since the mid-1990s, which relies on a combination of projected analyst EPS growth rates and GDP growth estimates, as we have used in our Multi-Stage DCF analysis.

Q. What are your conclusions regarding Dr. Booth's DCF analysis?

A. Dr. Booth's DCF analysis has limited value because much of the analysis is based on historical economic data and sustainable growth rates rather than forward-looking EPS growth rates for a proxy group of comparable risk to Newfoundland Power. The only DCF analysis that Dr. Booth presents using forecast EPS growth rates for a sample of U.S. electric utilities produces ROE estimates of 8.84 percent (mean) and 8.90 percent (median), not including 50 bps for flotation costs and financial flexibility. Only these DCF results of 9.34 percent and 9.40 percent using projected EPS growth rates should be given any weight by the Board.

42 British Columbia Utilities Commission, FortisBC Energy Inc., Decision and Order G-129-16, issued August 10, 2016, at 83.
43 *See* FERC Opinion No. 531, Order on Initial Decision, June 19, 2014.

VI. RISK ANALYSIS AND CAPITAL STRUCTURE

Q. Please summarize Dr. Booth's recommended capital structure for Newfoundland Power.

A. Dr. Booth recommends a reduction in Newfoundland Power's deemed equity ratio from 45.0 percent to 40.0 percent. This is consistent with his recommendations in prior GRAs involving Newfoundland Power. The Board has consistently rejected Dr. Booth's capital structure recommendation in previous Decisions.

Q. What is the rationale for Dr. Booth's recommendation to reduce the Company's deemed common equity ratio?

A. Dr. Booth starts his discussion of business risk by comparing Newfoundland Power's deemed equity ratio to that of other Fortis subsidiaries, specifically FortisAlberta, Maritime Electric, FortisOntario, and FortisBC Electric. Dr. Booth concludes that, "[c]onsequently, the range in similar utilities to NP is 37-41%, with NP being a distinct outlier at 45%; that can only be justified if NP is actually of higher risk than any of these other electric utilities, which I don't see as being the case."[44]

Q. How do you respond to Dr. Booth on this point?

A. While we agree with Dr. Booth that it is common practice among Canadian regulators to set the deemed equity ratio based on an assessment of business risk, a simple comparison of Newfoundland's Power's deemed equity ratio to that of other Fortis electric subsidiaries in Canada does not paint a complete picture. In addition, it is also necessary to consider the authorized ROE of these other Fortis electric utilities. As shown in Figure 6, the currently authorized ROE (as of May 2024) for these Fortis

[44] Evidence of Laurence D. Booth, at 92.

electric subsidiaries ranges from 9.21 percent to 9.65 percent, while Newfoundland Power is an outlier in all of Canada with an 8.50 percent authorized ROE. In its April 2024 Credit Opinion on Newfoundland Power, Moody's comments that the Company's authorized ROE of 8.50 percent "remains relatively low" it is "mitigated by one of the highest deemed equity levels in Canada that remains unchanged at 45%."[45]

Figure 6: Returns of Fortis Electric Utilities in Canada

	Equity Ratio	Authorized ROE	Weighted ROE
FortisAlberta	37.0%	9.28%	3.43%
Maritime Electric	40.0%	9.35%	3.74%
FortisOntario	40.0%	9.21%	3.68%
FortisBC Electric	41.0%	9.65%	3.96%
Newfoundland Power	45.0%	8.50%	3.83%

Dr. Booth has presented no evidence regarding the business risk of Newfoundland Power relative to those other Fortis electric utilities. Further, Dr. Booth states that he continues to view Newfoundland Power as an average risk Canadian utility. In previous decisions, the Board has consistently found that the business risk (in particular the small size and lack of geographic diversification) of Newfoundland Power supports an equity ratio of 45.0 percent. Dr. Booth has not provided any persuasive evidence to support his recommendation that the Board should change its longstanding view that the business risk profile of Newfoundland Power supports the Company's common equity ratio of 45.0 percent, not Dr. Booth's recommendation of 40.0 percent. Moreover, it is not appropriate to only compare Newfoundland Power to other Fortis subsidiaries in Canada, because the Company is competing for capital

45 Moody's Investor Service, Credit Opinion Newfoundland Power Inc., April 30, 2024, at 4.

in a global market (including the U.S.) and must offer a comparable risk-adjusted return to investors.

Q. Please summarize your response to Dr. Booth's evidence comparing the authorized ROE and deemed equity of Newfoundland Power to other Canadian electricity distributors owned by Fortis.

A. First, Dr. Booth has not included comparable risk U.S. utilities in his comparison even though there is evidence that companies such as Newfoundland Power are competing for capital in global financial markets, not just in Canada. Second, as mentioned previously, Dr. Booth has not conducted a comparative risk assessment to these utilities that would support such a conclusion. Third, Dr. Booth's recommended equity ratio and ROE would result in the lowest overall return for any investor-owned Canadian or U.S. utility.

Q. Does Dr. Booth offer any further rationale for reducing Newfoundland Power's deemed equity ratio?

A. Yes. Dr. Booth presents an analysis that purportedly measures Newfoundland Power's short-term business risk by looking at the Company's ability to earn its authorized ROE. His analysis finds that Newfoundland Power has consistently earned approximately 25 basis points above its authorized ROE over the last 30 years, and he concludes that, "On the basis of its demonstrated ability to earn its authorized ROE, NP has not suffered any risk whatsoever."[46] Dr. Booth also claims that, "To the extent NP is on top of its forecasting and risk assessment, the impact of some customer losses is not material as its ROE history demonstrates."[47]

[46] Evidence of Laurence D. Booth, at 97.
[47] Ibid, at 98.

Q. Do you agree with Dr. Booth that Newfoundland Power's ability to consistently earn its allowed ROE is evidence of the Company's low business risk going forward?

A. No, we do not. First, under the regulatory compact, a regulated utility has an *opportunity* to earn its allowed ROE, not a guarantee. Second, the fact that Newfoundland Power has historically been able to earn its authorized ROE in most years through efficient and economical management does not tell us anything about the future, nor should the Company be penalized for doing so. Lastly, Dr. Booth suggests that Newfoundland Power has no short-term risk because of its ability to accurately forecast demand. However, under the rate mitigation plan announced by the Provincial government on May 16, 2024, residential customer rates will increase by 2.25 percent per year through 2030 to recover costs associated with the Muskrat Falls project.[48] Although Newfoundland Power's average monthly bill for residential customers is currently lower compared to most other provinces, the expected increase in electricity prices is likely to affect demand for residential and commercial customers of Newfoundland Power, who may increase conservation efforts or consider alternative energy solutions. As shown by the demand elasticity study discussed in Newfoundland Power's evidence on business risk, higher prices inevitably lead to lower demand; it's only a matter of the degree. In addition, the rating agencies have expressed concern that the Board may continue to seek ways to mitigate rate pressure for customers, which could mean it is more difficult for Newfoundland Power to recover its costs and earn its allowed ROE.

[48] Through normal regulatory process, the PUB may approve additional rate changes resulting from Newfoundland Power general rate applications, rate stabilization, or municipal tax account or other adjustments.

Q. Have other regulators considered, and rejected, Dr. Booth's arguments pertaining to the ability to earn the authorized ROE as evidence of a company's business risk going forward?

A. Yes. The BCUC, in its 2016 cost of capital decision for FortisBC, heard this argument and rejected it, summarizing:

> *The impact of short-term risk on overall risk, and whether a short-term risk if never realized over a period of time should be considered a long-term risk and evaluated as such was raised by the parties. Specifically, this issue related to FEI's history of achieving actual earnings higher than its allowed ROE and whether the risk of not earning the allowed ROE should be considered a risk at all when viewed in the context of FEI's historical ROE performance.*
>
> *Mr. Coyne explains that business and financial risks also have a time dimension and both long and short-term risks are considered by investors and affect a utility's business risk profile. He describes short-term risks as those that will reverse and resolve themselves within a one to two year period through either the normal ebb or flow of earnings or through regulatory relief as a utility's short-term risk. Examples of these could include weather events or financial market disruptions. By contrast, longer term risks are those characterized by a business profile shift where mitigation is not foreseeable. Included among his examples of long-term risk is the risk of stranded assets because of market share losses or changes in environmental policies with a substantial impact on operational profitability.*
>
> *Dr. Booth describes the ability to earn the allowed ROE, reflecting a return on capital, as short-run risk. The return of capital is a long-run risk reflecting the utility's ability to recover its investment in plant and equipment. Dr. Booth asserts however, that to have any impact, long-term risks must eventually become short-term risks and states that: "To all intents and purposes FEI's shareholders have not suffered any losses or experienced any risk." Further, when such serious risks do arise, Canadian utilities typically come before the regulator for a reallocation of costs. Further, AMPC/BCOAPO, with reference to the earning of ROE, explain neither they nor Dr. Booth take issue with FEI's position that the ability to earn ROE in a particular test year represents short term risk. However, they contend that year after year "FEI continues to face very little short-run risk, such that this pattern of consistent overearning is clearly a long-term phenomenon" and pose the question as to how many years of persistent over-earning does it take for a utility witness to accept the limited risk faced by utility investors.*

....

The Panel does not agree with CEC's assertion that equity investors are concerned primarily with immediate risk and current ROE performance as they can alter their investment when rewards fail to match the immediate risk. While investors certainly consider a risk which has recently occurred, they must be equally concerned about the future prospects of an investment. Further, while it is true investors may sell a particular investment; it would be imprudent of an investor to fail to consider the future prospects of an investment and any potential future risks which may occur.

The Panel accepts FEI's argument that risk is prospective. In the Panel's view, the risk of earning ROE does not disappear in any given test year because of a utility's success in achieving it in prior years. However, this does not mean that an investor does not consider historical performance when choosing to make an investment but in doing so must accept that there is no certainty that past performance will be repeated in the future.[49]

Q. Dr. Booth also contends that Newfoundland Power's long-term risk of capital recovery has decreased. Do you agree?

A. No, we strongly disagree. On pages 97-99 of his Evidence, Dr. Booth argues that Newfoundland Power's capital recovery risk has decreased since the last litigated hearing in 2016, with the main reason being that "alternative fuels used to compete with NP are carbon based such as heating oil." Dr. Booth claims that, "Currently electricity has a 10-15% advantage over fuel oil, and the penetration of subsidy supported heat pumps will only increase this in tandem with increased carbon charges on fuel oil." On that basis, Dr. Booth concludes that, "Given NP's monopoly position in distributing electricity in Newfoundland, it is difficult to see how its risk has not gone down." Dr. Booth also states: "The fact is that in the long run all fossil fuel sources are under threat from current Government of Canada policy. Therefore,

[49] BCUC, Decision and Order G-129-16, August 10, 2016, at 10-11.

the only real question is how high can electricity prices go before people switch to heating oil despite the carbon tax and its other undesirable features."

Q. What is your response to Dr. Booth on these points?

A. First, we do not agree with the narrow basis of comparison to the 2016/2017 GRA. As recently as Order No. P.U. 3(2022), the Board approved the settlement agreement that included continuation of Newfoundland Power's deemed capital structure, which has included a deemed equity ratio of 45.0 percent for many years. Second, the Provincial government's recently announced rate mitigation plan provides short-term certainty around increases in power supply costs from Newfoundland and Labrador Hydro ("Hydro") for Muskrat Falls related costs through 2030, but it does not provide any rate certainty for other costs or beyond that point in time. From a cost of capital perspective, investors are primarily concerned with longer term risks that affect the ability of a company such as Newfoundland Power to recover its prudently incurred costs and to earn its authorized return. Moreover, the rate mitigation plan does nothing to reduce the risk associated with reliability concerns on the Labrador Island Link. As discussed on page 66-67 of our Report, to help ensure reliable service for customers, Hydro has committed to maintaining the Holyrood TGS and Hardwoods Gas Turbine possibly through to 2030 and Hydro is considering the need to replace Holyrood with a new generation facility to provide additional capacity. Third, it is important to remember that under the Fair Return Standard, the cost of equity must be set according to the three-pronged test of capital attraction, comparability of returns, and financial integrity. This standard is designed to determine a fair return to the shareholder for its invested capital and is not a lever to be used to mitigate rate impacts.

Further, Moody's recently reaffirmed its rating on Newfoundland Power while commenting on how the rate pressure from higher electricity costs creates recovery uncertainty for the Company. A few highlights from the April 2024 Moody's report are as follows:[50]

- *The total cost of Muskrat Falls and associated transmission in Newfoundland and Labrador increased to about CAD13.5 billion, up from an initial cost estimate of CAD7.4 billion. The size of the project and associated rate increases are exacerbated by the relatively small size of NPI and the Newfoundland and Labrador economy.*

- *Given some operational challenges on LIL, the 490 MW Holyrood thermal generation may remain operational through the end of the decade as backup generation which would also add to customer rate pressure.*

- *One of the rate mitigation actions in 2023 included the provincial government providing CAD190.4 million of rate mitigation to NL Hydro to offset energy supply cost increases. The federal government has provided support that includes but is not limited to guarantees for billions of dollars of debt related to the project.*

- *NPI is allowed to pass through the increase in power supply costs to customers. The increase in rates from the project may lead to lower electricity demand resulting in lower revenues and cash flow, although the difference is expected to be temporary in nature as we expect power supply costs to remain a pass through.*

As outlined by Moody's, there is no basis to suggest that Newfoundland Power's business risk has decreased.

Q. Has Dr. Booth taken into consideration the small size of Newfoundland Power in his risk assessment?

A. No. Dr. Booth states that he does not consider Newfoundland Power a small utility, based on a comparison to other Fortis electric subsidiaries in Canada.[51] As discussed

[50] Moody's Investors Service, Credit Opinion Newfoundland Power Inc., April 30, 2024, at 4-5.
[51] Evidence of Laurence D. Booth, at 101-102.

in our Report, however, the Board has previously found that the small size of Newfoundland Power is one of the key factors supporting the Company's common equity ratio of 45.0 percent.[52] This finding has been recognized by the Board in determining the equity ratio for Newfoundland Power. Furthermore, the small size of Newfoundland Power actually has had a negative effect on the Company's borrowing costs because Newfoundland Power's bond issuances are typically in the range of $75 million to $100 million with fewer than 10 investors, whereas 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.[53] The size of Newfoundland Power's debt offerings contributes to liquidity constraints in placing the debt and in higher pricing differentials with Canadian long bonds. In addition, the Company's other business risks are magnified by Newfoundland Power's small size. In summary, the small size of Newfoundland Power runs counter to Dr. Booth's recommendation to reduce the Company's common equity ratio.

Q. Has Dr. Booth considered the economic outlook and demographic trends for Newfoundland and Labrador relative to Canada generally?

A. No. Dr. Booth fails to recognize that Newfoundland and Labrador is a relatively small economy and lacks the economic diversification of many other Canadian provinces. In addition, as discussed in our Report, the long-term economic outlook for the province is weak as compared to Canada overall and long-term demographic trends including a declining and aging population are less favorable in the province than

52 Concentric Cost of Capital Report, Volume 2, at 61.
53 Ibid, at 63.

elsewhere in Canada.[54] These factors adversely affect the business risk of Newfoundland Power and make the Company riskier from the perspective of investors and credit rating agencies than companies that operate in larger, more economically diverse service territories. Against this economic backdrop, it is reasonable to conclude that Newfoundland Power's business risk is higher than other Canadian utilities. Nevertheless, Newfoundland Power must continue to invest in its distribution and transmission system so that it can continue to provide safe and reliable service and meet service quality and customer satisfaction standards. In our view, the longer-term economic outlook and demographic trends for Newfoundland and Labrador contribute to the higher business risk of Newfoundland Power, and support continuation of the Company's 45.0 percent deemed equity ratio.

Q. How does Dr. Booth support his assertion that Newfoundland Power has very low business risk?

A. Dr. Booth states that "NP has been allowed a band around its rate of return that translates into approximately +/- 0.40% on its ROE."[55] He also observes that since 1995 Newfoundland Power has earned on average approximately 43 basis points above the authorized ROE before the operation of the earnings sharing mechanism. Based on this statement, Dr. Booth apparently includes the range approved by the Board, but he does not consider the earnings upside of other Canadian utilities in his comparisons, as noted previously in this Rebuttal. Dr. Booth concludes his analysis of the Company's short-term business risk by stating: "However, as shown by NP's subsequently demonstrated ability at earning its allowed ROE, these risks have not

[54] Concentric's Cost of Capital Report, Volume 2, at 65-66.
[55] Evidence of Laurence D. Booth, at 96-97.

generated any 'losses' to the shareholder where the subpar ROEs were largely based on CRA reassessments that were subsequently reversed."[56]

Q. Dr. Booth claims that Newfoundland Power would still be able to access capital on reasonable terms if the Company's deemed equity ratio were reduced from 45.0 percent to 40.0 percent.[57] Please comment.

A. As a preliminary matter, we do not agree with Dr. Booth that Newfoundland Power has a higher credit rating than other electric and gas utilities in Canada. Newfoundland Power has a long-term issuer rating of Baa1 from Moody's, not 'A2' as Dr. Booth asserts. The 'A2' rating is an issue rating for First Mortgage Bonds ("FMB") that are secured by Company assets. This pledge of security enables the FMB to receive a rating two notches higher than Newfoundland Power's issuer rating. Dr. Booth is incorrectly comparing the issue rating of Newfoundland Power to the long-term issuer rating (which is what we use to screen our proxy group companies) of other Canadian utilities. As explained above, the issue rating for Newfoundland Power is higher because the Company issues FMBs, not unsecured debt. Further, our research indicates that Newfoundland Power is one of two regulated utilities in Canada to have issued FMBs in the past 20 years (Maritime Electric Company is the other), and both are small electric utility companies.

As support for his assertion, Dr. Booth refers to an analysis performed by the AUC, which evaluates whether the AUC's authorized ROE and capital structure would allow the regulated utilities in that province to achieve an A range credit rating from S&P.

[56] Ibid, at 98.
[57] Ibid, at 115.

Using the AUC table, Dr. Booth finds that Newfoundland Power would have a coverage ratio of 3.2 with its current 8.5 percent authorized ROE and 45.0 percent equity ratio.[58] Dr. Booth, however, does not indicate what Newfoundland Power's coverage ratio would be using his recommended ROE of 7.7 percent and his equity ratio of 40.0 percent, or whether that coverage ratio would be sufficient to achieve or maintain an A range bond rating.

Q. Have the credit rating agencies recently expressed any concerns with Newfoundland Power's credit metrics?

A. Yes. In response to Dr. Booth's comments regarding whether a deemed equity ratio of 40.0 percent or lower would allow Newfoundland Power to maintain its current credit rating, we note that Moody's and DBRS Morningstar consider both business and financial risk when they assign a credit rating.[59] Even though Moody's views Newfoundland Power among the broad category of relatively low risk regulated utilities, Moody's recently commented on the decline in credit metrics for Newfoundland Power as follows:

> *The credit profile has been negatively affected by temporarily weak financial metrics including a CFO pre-W/C to debt ratio falling to 12.6% at 31 December 2023, primarily caused by the under-recovery of power costs in 2023. We expect the company to fully recover these costs based on established cost recovery mechanisms starting on 1 July 2024. Significant upward pressure on rates can be attributed to NL Hydro's completion of the Muskrat Falls hydro-electric generating station and related projects with a cost of CAD13.5 billion, with only a fraction of these costs currently reflected in rates.*[60]

[58] Evidence of Laurence D. Booth, at 114-115.
[59] *See* response to CA-NP-081, Attachment A, for a copy of Moody's rating methodology for regulated utilities.
[60] Moody's Investors Service, Credit Opinion Newfoundland Power Inc., April 30, 2024, at 1.

While bond ratings are one important consideration for investors, equity investors tend to be more concerned with earnings growth rates, valuation multiples (such as the P/E ratio), the economic outlook for the Company's service territory, and the regulatory environment in which the Company operates. In order to meet the Fair Return Standard, an equity return must do more than achieve a minimal bond rating.

Q. Are you aware of any instances where a reduction in the authorized equity ratio resulted in a downgrade to the utility's credit rating?

A. Yes, the New York Public Service Commission approved a settlement agreement for Central Hudson Electric and Gas Company ("Central Hudson"), another Fortis subsidiary, which included a reduction in that company's authorized equity ratio from 50.0 percent to 48.0 percent and an increase in the authorized ROE from 8.80 percent to 9.00 percent. Moody's subsequently downgraded the credit rating of Central Hudson on September 22, 2021, from A3 to Baa1, citing the lower equity ratio as a primary factor in the rating downgrade. Moody's explained the rationale for the downgrade as follows:

> *Several factors incorporated in the proposal will contribute to the weakness in financial metrics including growth in regulatory assets combined with a reduction in regulatory liabilities and a reduction in equity capital from 50% to 48% over the next 3 years and a large ongoing capital program. These factors are only partially offset by an increase in the allowed ROE to 9%.*[61]

Moody's also commented on how the New York PSC's decision affected their view of the regulatory environment in New York, stating:

[61] Moody's Investors Service, "Rating Action – Moody's downgrades Central Hudson Gas & Electric to Baa1; stable outlook, September 22, 2021, at 1.

> *While we don't believe that Central Hudson has been a significant target of such actions, these efforts undermine the consistency and predictability of the state's regulatory framework, an important credit consideration.*[62]

This Moody's report on Central Hudson highlights the importance of a regulatory environment that supports the utility's ability to maintain its financial strength and ability to access capital under a variety of economic and financial market conditions.

Q. Do you have any concluding comments on Dr. Booth's recommendation to reduce the common equity ratio of Newfoundland Power?

A. Yes. In previous GRA filings, the Consumer Advocate has made a similar recommendation to reduce the Company's common equity ratio and has typically proposed that this change in capital structure be accomplished by issuing preferred shares or by substituting the cost rate for preferred shares for the 5.00 percent of common equity. The Board has rejected this proposal on several previous occasions.

Q. What are the implications of deeming 5.0 percent of Newfoundland Power's capital structure as preferred shares, as Dr. Booth recommends?[63]

A. If the Board were to modify Newfoundland Power's deemed capital structure to include 5.0 percent preferred shares, Dr. Booth recommends that the return on those preferred shares be based on Fortis Inc.'s cost of preferred equity. However, from a practical perspective, this is not a viable option for Newfoundland Power because the market for preferred shares in Canada has shrunk, and most utilities in Canada no longer issue preferred shares. In summary, Dr. Booth's recommendation to reduce the equity ratio in the capital structure has been rejected by the Board previously, and the Board should reiterate that decision in this proceeding.

[62] Ibid.
[63] Evidence of Laurence D. Booth, at 112-113.

VII. CONCLUSIONS AND RECOMMENDATION

Q. What is your conclusion regarding a reasonable and appropriate cost of equity and equity ratio for Newfoundland Power?

A. We affirm our recommendations from our Report. Based on that analysis, a just and reasonable ROE for Newfoundland Power is 9.85 percent and the deemed equity ratio should remain at 45.0 percent common equity.

Q. Does this conclude your Prepared Rebuttal Testimony?

A. Yes, it does.