DECISION **2023 NSUARB 207**
M11199

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF AN APPLICATION by the **BERWICK ELECTRIC COMMISSION** for Approval of Amendments to its Schedule of Rates and Charges for the provision of electric supply and services to its customers and its Schedule of Rules and Regulations

BEFORE: Stephen T. McGrath, K.C., Chair
Jennifer L. Nicholson, CPA, CA, Member

APPLICANT: **BERWICK ELECTRIC COMMISSION**
James MacDuff, Counsel

INTERVENOR: **NOVA SCOTIA POWER INCORPORATED**
Blake Williams, Counsel
Mollie Morris, Counsel

BOARD COUNSEL: William L. Mahody, K.C.

HEARING DATE: October 12, 2023

FINAL SUBMISSIONS: October 26, 2023

DECISION DATE: **November 24, 2023**

DECISION: **Application is approved, effective the date of this decision, subject to changes and directions in this decision, to be confirmed in a compliance filing.**

Table of Contents

1.0 INTRODUCTION

[1] The Berwick Electric Commission (BEC) applied to the Nova Scotia Utility and Review Board to amend its rates for electric supply and services. Citing a significant increase in the costs of its power supplies, the utility requested an overall average rate increase of 17.9%. BEC also seeks increases in its pole attachment and inspection fees. The Board approved the utility's last general rate application in January 2021.

[2] On October 12, 2023, the Board held a public hearing in the Town of Berwick Council Chambers. The hearing was also live streamed. Donald Regan, BEC's Superintendent; and Lisa Buchan, the Town's Director of Finance, testified on behalf of the utility. Aaron Long, General Manager of the Alternative Resource Energy Authority (AREA), also appeared in person to testify for the utility. BEC's consultants, Paula Zarnett and Trent Winstone, both of BDR NorthAmerica Inc., appeared virtually. Board Counsel consultant, Ben Havumaki, Synapse Energy Economics, Inc., also testified virtually.

[3] In its application and during this proceeding, BEC claimed confidentiality over certain information filed or presented to the Board. The Board accepts the claims for confidentiality.

[4] The Board approves BEC's application subject to the adjustments and directives in this decision.

2.0 BACKGROUND

[5] BEC is owned by the Town of Berwick and operates as a management board appointed by the Town Council under the *Berwick Electric Commission Act*, S.N.S. 1977, c. 84. Through its distribution system, it serves approximately 1,550 metered

customers (as well as 415 unmetered lighting and other small services) in the Town and adjacent areas of Kings County. In recent years, BEC has experienced modest growth in its customer base and total energy sold. The utility forecasts a system peak for the calendar year 2023 at 7,340 kW.

[6] BEC operates a hydro generating station at Factorydale. It also supplies its customers with energy produced by the Ellershouse Wind Farm under a separate wind contract through AREA and energy from Nova Scotia Power Incorporated under its Board-approved tariff for municipal electric utilities. In 2023, BEC also expects solar power from the Town's newly constructed solar garden.

[7] The Board approved BEC's current rates in 2021 (2021 NSUARB 6). The utility says that it cannot continue without a rate increase because of escalating costs, especially the cost of purchased power. BEC advised that, through AREA, and in the context of the serious escalation of fuel prices in world markets, it recently sought contracts for its wholesale supply of electricity for 2023. The utility says that, after evaluating several alternatives, it decided to take supply from NS Power. BEC estimates, based on NS Power's Board-approved rates and the costs of the utility's other power supplies and forecast loads, that its cost of purchased power will increase by approximately 20% in 2023 on an annualized per kWh basis. It is concerned that its purchased power costs will continue to increase by a further significant amount in the years following.

[8] BEC projects an operating loss in the current financial year and a loss of $735,906 in the 2023 test year at its current rates. BEC has concluded that it cannot continue to provide service at its currently approved rates without severe detriment to its

financial integrity. As filed, BEC's general rate application proposes an overall average rate increase of 17.9%.

3.0 DISCUSSION AND ANALYSIS

3.1 Revenue Requirement

[9] BEC is requesting approval of a revenue requirement of $6,748,158 for the test year. This includes the total cost of purchased power, operations and maintenance costs, administrative and general costs, and amortization, plus $318,085 for a proposed return on rate base of 6%. Aside from the return on rate base, the Board finds the revenue requirement for the test year is reasonable. Certain components are discussed in more detail below, including the claimed cost of capital, which the Board finds should be adjusted.

3.1.1 Purchased Power Costs

[10] In the test year, BEC expects to be supplied power from four sources: its Factorydale Hydro Power Plant; its share of energy produced by the Ellershouse Wind Farm under a separate wind contract through AREA; solar power from the Town's newly constructed solar garden; and energy purchased from NS Power under its Board-approved tariff for municipal electric utilities. In its application, BEC forecast purchased power costs of approximately $4.7 million by applying the rates it expected to pay for electricity in the test year to its forecast of weather-normalized electricity sales to serve its customers, and system losses of 4.3%. Purchased power is the largest component of BEC's total operating costs and is forecasted to increase by approximately 20%, representing the most significant component of BEC's increased revenue requirement for the test year, as compared to 2022.

[11] AREA is an inter-municipal agency that procures all power supply for BEC, as well as for other Nova Scotia municipal electric utilities. Considering the serious escalation of fuel prices, AREA sought new arrangements for BEC's wholesale supply of electricity. After evaluating several alternatives, the decision was made to change suppliers and purchase power from NS Power. BEC believes that this supply arrangement with NS Power represents the best alternative available for its customers in terms of both price and security of supply for the test year.

3.1.1.1 Findings

[12] The Board considers the estimated purchased power costs to be reasonable.

3.1.2 Administrative and General Expenses

[13] BEC forecast its administrative and general expenses for the test year using the amounts from its 2022/23 budget (fiscal year ended March 31, 2023) but with an increase of $65,000. This includes $25,000 for its cost allocation study, and $40,000 for legal and consulting costs related to this general rate application (GRA). Legal and consulting fees related to this GRA total $80,000 but half of that is being deferred until next year to reduce the impact on customers. This $80,000 is not subject to interest or other carrying costs.

[14] BEC noted that there was an increase of 11.7% in salaries from 2021 to 2022 at the utility and a 5.4% increase from 2022 to 2023. BEC has shared staff with the Town of Berwick since the Commission was established in 1977. Administration functions are based on estimates from work performed. Operations and maintenance support are expensed to BEC on an as incurred basis. The allocation percentages are reviewed

annually. The allocation of administrative salaries has been revised to better reflect the support provided. This resulted in a $45,000 increase in the administrative charge from the Town. BEC has also budgeted for an additional powerline technician to improve service and reduce the overtime paid to the existing three technicians.

3.1.2.1 Findings

[15] The Board has some concern about the costs of this rate application being included in rates if BEC does not submit another rate application for 2025. The Board is concerned about including costs that are no longer applicable in rates. However, the Board also recognizes that there are studies and projects that BEC has proposed to undertake before its next GRA that have not been included in its revenue requirement and could be offset by this allowance if its next general rate application is later than anticipated.

[16] Overall, the Board concludes the forecast administrative costs appear reasonable. The Board encourages BEC to continue to identify operational areas of improvement and to develop and implement solutions that will result in the most efficient business processes for the benefit of ratepayers.

3.1.3 Storm Costs

[17] BEC does not have a separate line item for storm costs. Due to its location in a valley, Berwick does not tend to receive a lot of storm damage. The Board asked for an undertaking showing costs incurred during hurricane Dorian which happened in September 2019 and caused the most damage of any hurricane in recent memory in Berwick. Total costs for that storm restoration were about $35,000.

3.1.3.1 Findings

[18] Annual costs for storm restoration are minimal. When there is more significant storm damage, costs are covered within the operating budget. The Board is satisfied that a separate budget line item for storm restoration costs is not required at this time. However, it would be prudent to track these costs to assess whether they are increasing.

3.1.4 Depreciation Expense

[19] In Exhibit 1-2 Net Plant (Exhibit B-1), BEC calculated the depreciation expense for each class of assets. This resulted in an expense of $368,384. BEC then applied a pro rata adjustment to reach the budgeted depreciation expense of $325,000 which was used in the rate application. The Board directed BEC in an undertaking to calculate the depreciation expense based on a build up from the 2022 historical allocations, accounting for any capital additions or disposals since then. The Board also asked for updated application exhibits and rates based on this calculation. The resulting depreciation expense of $368,384 matched the original depreciation calculation in Exhibit 1-2.

3.1.4.1 Findings

[20] The proposed adjustment to the utility’s depreciation expense is unusual. It is not clear to the Board why the utility felt it was necessary to limit this aspect of its request to what it budgeted. The impact of this decision somewhat understates the BEC’s revenue requirement and produces a correspondingly lower rate increase. Since it is favourable to BEC’s customers, the Board accepts the utility’s proposed adjustment.

The Board anticipates BEC will take a more traditional approach in its next GRA or provide additional justification to demonstrate the need for this adjustment.

3.1.5 Capital Costs

[21] BEC estimates its proposed capital costs in the test year at $350,000 with almost $260,000 going towards new and replacement transformers. The remaining spending is for electrical line replacements, meter purchases, street and yard lights, and contingencies.

3.1.5.1 Findings

[22] The Board considers the capital plan for the test year to be reasonable. Notwithstanding this conclusion, the Board reminds BEC that separate approval is required for each capital project over $250,000 under s. 35 of the *Public Utilities Act*.

3.1.6 Working Capital

[23] BEC is requesting approval of a working capital allowance of $610,507. This amount is based on an estimated 36 days' payment lag (10%) applied to its forecast $6,105,073 in net cash expenses (cost of purchased power and operations, maintenance, and administrative costs, but excluding amortization). BEC has not performed a lead-lag study. Instead, it submitted that a 36-day lag is reasonable for a utility that doesn't have automated meter reading and where half of metered revenues are billed bi-monthly.

[24] The requested amount is more than double the working capital allowance approved by the Board in BEC's last GRA under matter M09820. The estimate provided was based on default factors and a practice used by the Ontario Energy Board (OEB) for utilities without advanced metering infrastructure (AMI) meters and monthly billing.

[25] BEC noted that the OEB previously allowed 13% of net cash expenses, about equal to 47 days, when a lead-lag study was not undertaken. However, with the adoption of AMI and monthly billing, the OEB allows for 7.5% without a lead-lag study. BEC submitted that using 10% of net cash expenses would be reasonable, considering BEC bills every two months for all classes and does not have AMI.

[26] BEC identified that, at a minimum, it required $450,000 for working capital in recent years. During the highest point of its revenue-expense cycle, BEC required a minimum balance of $710,000.

[27] During the hearing, BEC was asked why it requested approval of $610,507 when it will sometimes need as much as $710,000. Ms. Zarnett explained that the requested working capital is based on the total annual expenses and reflects the typical need throughout the year. The $710,000 would reflect the most that BEC would need rather than what BEC needs in a typical month.

3.1.6.1 Findings

[28] The Board recognizes that the utility requires a reasonable amount of working capital but is concerned that a working capital allowance that is too high could reduce BEC's motivation to review its operations to find efficiencies. Without a lead-lag study the Board has concerns about the reasonableness of BEC's requested working capital amount but will allow BEC to use 10% of net cash expenses in this proceeding.

[29] The Board understands the potential costs involved in a lead-lag study for BEC; however, the Board expects some assessment based on BEC's information to be included in the next GRA. Alternatively, the Board encourages BEC to consider whether a collaborative lead-lag study with other municipal electric utilities in Nova Scotia

may be a cost-effective alternative to assess the utility's requirement for working capital based on information that is more closely related to its operations and jurisdiction.

3.1.7 Capital Structure and Rate of Return

[30] BEC asked the Board to approve a rate of return on its rate base (or a weighted average return on capital) of 6% based on a capital structure of 60% debt and 40% equity. BEC estimated that its cost of debt is 5% and requested a return on equity of 7.5%. BEC said the deemed capital structure was consistent with the structure NS Power proposed in its recent GRA and that was found to be reasonable for small distribution utilities elsewhere in Canada.

[31] BEC estimated that its cost of debt is 5% based on the current rates available from the Municipal Finance Corporation. BEC noted that it did not intend to add to its long-term debt if the test year revenue requirement was approved by the Board. Instead, BEC planned to fund capital expenditures with depreciation, which is the typical approach it applies to funding long-term assets of 20 years or more.

[32] At the hearing, BEC was questioned on its current debt rate.

> Q. ….
>
> Am I correct that the debt rate for 2021, the electric utility's debt rate, was 3.01 percent and in 2022, it's 3.37 percent?
>
> A. (Buchan) Yes, that's as it's presented.
>
> Q. As it's presented, right.
>
> But that is the average debt rate for the utility in those years, isn't it?
>
> A. (Buchan) Yes.
>
> Q. And in 2023, there's no additional debt that was requested?
>
> A. (Buchan) That's correct.
>
> Q. And so is it fair to say that your actual debt rate would be comparable to what we see in the table?

A. (Buchan) For the test year, yes.

Q. For the test year, right. So it's not -- you're not expecting an actual debt rate of five percent in the test year?

A. (Buchan) That's correct.

[Transcript, pp. 65-66]

[33] The Board notes that BEC's requested return on equity is significantly higher than the effective return in its previous GRA. In its response to Board IR-21, BEC cited recent interest rate increases in Canada. Considering return on equity typically adds a risk premium over the rate for debt, BEC considers the requested 7.5% to be reasonable and consistent with what the Board recently approved for other municipal electric utilities.

[34] In response to IR-10, BEC indicated that it would not pay the Town of Berwick a dividend in 2023, to reduce the impact of the rate increase on its customers. At the hearing, Mr. Regan agreed that by requesting a return on equity the Commission will generate a profit. He confirmed that the profit is not intended to be paid as a dividend to the Town of Berwick.

[35] BEC's proposed 7.5% return on equity was not based on a utility-specific assessment of its investment needs, risk or financial requirements. Instead, the utility's requested rate of return was benchmarked against other Nova Scotia electric utilities.

3.1.7.1 Findings

[36] The fair return requirement and standard was discussed in detail in the Board's decision in NS Power's recent GRA [2023 NSUARB 12 (*NS Power 2023-2024 Rate Application*), paras. 227-237]. Section 45 of the *Public Utilities Act* entitles a utility to earn a just and reasonable return on its rate base, in addition to the recovery of its operating expenses and other just allowances.

[37] In *NS Power 2023-2024 Rate Application*, the Board reviewed the legal precedents and principles applied to determine a reasonable rate of return and noted that the assessment of these principles in any case before the Board is based on the evidence presented. This typically involves evidence and opinions from cost of capital experts considering matters such as the following:

- The return must be comparable to the return available in the market on an investment of similar risk: the comparable investment or earning principle.
- The return must be sufficient to attract new utility capital investment: the capital attraction principle.
- The return must be sufficient to maintain the financial integrity of the utility: the financial integrity principle.

[*Energy Law and Policy* (Kaizer and Heggie, Ed. 2011)]

[38] In the present case, the evidence provided to the Board assumed a cost of debt of 5% for new debt that the utility would take on during the test period. However, BEC specified in its application that it did not intend to increase its debt to finance capital additions, instead preferring to fund future capital expenditures with depreciation. The Board finds that a cost of debt of 3% more accurately reflects BEC's liabilities that will come due during the test year. Additionally, this is the cost of debt the Board approved earlier this year for two other municipal electric utilities and the Board finds that the evidence in this proceeding does not warrant different treatment for BEC.

[39] The evidence supporting the utility's request for a return on equity was minimal. No evidence was presented by experts qualified to provide an opinion on BEC's cost of capital. Instead, the requested return on equity was benchmarked against other Nova Scotia electric utilities.

[40] While the Board appreciates that a cost of capital study comparable to what was before the Board in *NS Power 2023-2024 Rate Application* would be a

significant cost for a small utility such as BEC, the evidence provided in this proceeding does not provide the Board with the information needed to satisfactorily assess a fair return.

[41] This is the same situation that was before the Board when it considered the recent general rate applications by the Riverport Electric Light Commission (RELC) [2023 NSUARB 56] and the Town of Mahone Bay Electric Utility [2023 NSUARB 66]. In those cases, the Board recognized the utilities' underlying entitlement to a rate of return under s. 45 of the *Public Utilities Act* but considered the utilities did not adequately meet the burden upon them to demonstrate that their requested return was reasonable. For the same reasons expressed in those cases, the Board finds that a rate of return on equity of 7.5% is appropriate.

[42] In its compliance filing in this matter, the Board directs BEC to set its rates using a cost of debt of 3% and its requested rate of return on equity of 7.5%.

3.2 Cost of Service

[43] BDR prepared the Rate Study for this application. In response to Board IR-37, the methodology used in the study was compared to BEC's rate application in 2020:

> The following table identifies the methodology associated with classification and allocation of the costs, as compared with the 2020 Rate Study. Identification of the 2020 methodologies in this table are from the factors as identified in the tables filed at that time. Neither BEC nor its consultants are aware of any documentation at that time as to the methodology choices, nor were any working papers available.
>
> For this application, the level of detail of line items was taken as available in BEC's accounts and budget, and is not identical with 2020, specifically as regards "miscellaneous generation assets" and general expenses. In the case of general expenses, a method used in other recent cases was adopted.
>
> In the course of the work, there were discussions as to the use of general plant in support of BEC's system (i.e. generation, transmission, substations, and elements of the distribution system). For this study, there was some discussion of whether the general plant supports all classes of system assets, but no analysis is available to support a breakdown.

Therefore a simplifying assumption was made to use derived factors based on distribution assets only, pending review in the future.

For miscellaneous (non electricity sales) revenues, a method consistent with recent Board approvals was adopted.

Item	Proposed by BEC	BEC 2020 GRA
Classification of Generation Dams and Reservoirs	100% energy	Same
Classification of Generation Prime Movers, Roads, Trails and Bridges	100% demand	Same
Classification of all other specific generation plant	By capacity factor (D/E)	Same
Classification of miscellaneous generation assets	Weighted average of specific generation assets	No comparable asset group
Transmission Right of Way	System Load Factor to CP (D/E)	Same
Substations	System Load Factor to CP (D/E)	Same
Classification of Conductors, Poles and Fixtures	70% Demand, 30% Customer	Same
Classification and Allocation of Street Lighting	Direct Assignment	Same
Classification of Transformers	100% Demand	Same
Classification of Services	100% Customer	Same
Classification of Meters	100% Customer	Same
Classification of General Plant	By total distribution assets; based on high level discussions about use of the plant.	Total all plant other than generation.
Classification of Working Capital	By total plant	Same
Allocation of Rate Base – Demand	Non-Coincident Peak	Same
Allocation of Rate Base – Customer	Weighted Customers	Same
Classification of Generation O&M	Generation rate base	Same
Classification of Distribution O&M	Distribution assets other than meters. No separate analysis to directly assign street lighting amounts.	Distribution, transmission and substation assets, excluding street lighting. Separate line for directly assigned street light O&M directly assigned.
Classification of Purchased Power	Demand and Energy as to be billed by supplier	Same

Item	Proposed by BEC	BEC 2020 GRA
Classification of Bad Debts	Customer	Bad debts not separated from other administrative costs.
Classification of Administrative or General Expenses	By rate Base; to reflect treatment accepted for other municipal utilities in recent cases.	Different breakdown of line items, not clearly documented.
Classification of Depreciation	Individually by asset class, same factor as used for the asset.	Same
Allocation of Power Demand	Coincident Peak Responsibility	Same
Allocation of Power Energy	Energy	Same
Allocation of Distribution Demand	Non-coincident peak	Same
Allocation of Distribution Customer	Weighted Customer; multiple factors	Same
Allocation of Lighting	Direct Assignment	Same
Allocation of Miscellaneous Revenues	Revenue items separately allocated, based on a variable considered to be related to each item, or rate base.	Distribution O&M Expenses
Interest and Net Income, Classification and Allocation	By total rate base	Same

[Exhibit B-4, IR-37]

[44] Mr. Havumaki considered the cost allocation methods in his evidence. Overall, he found the methods to be sound. He said the study was thorough and well documented, and that methodological decisions appeared to be reasonably supported. However, he had concerns that he felt warranted future attention, but which he did not consider compromised the overall reliability of BEC's cost allocation results in this proceeding. Mr. Havumaki's concerns related to the classification of some portions of the distribution system upstream of the customer service drop, BEC's estimated demand allocation factors, and the allocation of purchased power costs.

3.2.1 Classification of Distribution System Costs

[45] Mr. Havumaki questioned BEC's classification of distribution system costs upstream of the service drop. He said the approach BEC used is flawed because, in his view, "the relationship between costs incurred for these upstream assets and the number of customers on the system is tenuous." Mr. Havumaki acknowledged that the approach proposed by BEC was not an uncommon one for allocating distribution system costs in North America and was accepted by the Board in its recent decisions on the general rate applications filed by RELC and the Town of Mahone Bay (on behalf of its electric utility). While Mr. Havumaki agreed that methodological consistency was important, he did not consider the Board's earlier decision to be a "permanent endorsement" and encouraged the Board to establish a standard requiring all distribution system infrastructure, except meters and services, be classified as 100% demand-related.

3.2.1.1 Findings

[46] The approach used by BEC to allocate distribution system costs is one that has been commonly used by electric utilities in Nova Scotia, including NS Power and the Board concludes it is appropriate to continue with this approach at this time. The Board recognizes that there may be room to debate the merits of this approach, compared to the approach urged by Mr. Havumaki (and by Synapse in the recent RELC and Mahone Bay rate applications). However, the Board continues to hold the view that it expressed earlier this year:

> [90] The Board does not believe that a fundamental change to the utility's historical method of allocating its distribution system costs is appropriate at this time. In addition, there is value in ensuring some underlying consistency in the costing methodologies used amongst local electrical utilities, especially the smaller municipal utilities. As such, the Board accepts the methodology used in the Rate Study prepared for TOMBEU in this proceeding, except

> that transformers should be 100% demand-related, as was the case in TOMBEU's past applications. The Board anticipates that this issue may be one that is more thoroughly considered in this jurisdiction when NS Power completes its next cost-of-service study, which is expected no later than December 31, 2025.
>
> [*Mahone Bay (Town) (Re),* 2023 NSUARB 66]

3.2.2 Demand Allocation Factors

[47] In its rate study, BEC noted that the preferred approach to determining class coincident and non-coincident peaks would be to use hourly load data for each customer class, but BEC did not have hourly load data for any customer class except for the industrial class. Instead, BEC estimated load shapes for its residential and small general service classes using data from NS Power's time-varying pricing pilot application to the Board in 2020. BEC assumed that the usage patterns for NS Power's customers in these classes correspond to the load shapes for the same BEC customer classes. For its unmetered customers (i.e., lighting and cable power supplies), BEC estimated load shapes based on supply requirements for the equipment involved and its highly predictable operating patterns.

[48] BEC was less confident that the load profile of its general service customers was comparable to customers in NS Power's corresponding class. BEC noted that the average annual usage for customers in its and NS Power's general service classes were quite different. As a result, BEC calculated the coincident peak for its general service class by deducting the coincident peaks of its other service classes from its total distribution system peak load. BEC used a diversity factor to estimate the non-coincident peak for its general service class, which assumed that the coincident peak for its general service class was 80% of its non-coincident peak.

[49] Mr. Havumaki expressed concern about BEC's approach to estimating the coincident and non-coincident peaks for the general service class. He said because

the coincident peak for the general service class is a function of the coincident peaks of all other rate classes, the uncertainty associated with the coincident peak estimate for this class was the sum of the uncertainties associated with all other classes and this inherent uncertainty carries into the non-coincidental peak estimate. In his view, BEC should have presented an analysis using NS Power's general service class data as a sensitivity to determine the reasonableness of BEC's peak estimates for its general service class. At the hearing, Mr. Havumaki confirmed that he did not believe the approach BEC took was unreasonable; he just thought it would be useful to have the analysis based on the NS Power data to check the results of BEC's analysis.

3.2.2.1 Findings

[50] In the circumstances, the Board finds that BEC's peak estimates for the test year are reasonable; however, the Board appreciates the concern raised by Mr. Havumaki about the uncertainty associated with the general service peaks in particular. The Board notes that the capital plan BEC filed in response to Board IR-9 (Exhibit B-4(ii)) suggests the utility intends to convert to smart meters over a two-year period in fiscal years 2024-25 and 2025-26. If the utility goes ahead with this project, it may improve the data available to determine class peaks. BEC is directed to update the Board about this issue, and the accuracy of its general service peaks, in its next general rate application.

3.2.3 Allocation of Purchased Power Costs

[51] BEC classifies its purchased power costs as energy-related and demand-related. It allocates the energy-related costs to its customer classes based on their annual energy usage. Mr. Havumaki noted there is seasonal variation in the energy used by the various customer classes, especially in the energy used by residential

customers. This variation could result in cost differences through the year that would be different than those determined on an overall annual basis. Mr. Havumaki provided a confidential sample calculation to demonstrate this for the residential class, but the difference was quite small. He recommended that, in its next general rate application, BEC evaluate the implications of shifting to a monthly purchased power cost allocation using monthly energy allocators rather than allocating these costs on an overall annual basis.

[52] In its opening statement, BEC said it respected Mr. Havumaki's comments. However, it felt there was a balance to be struck between precision and the need for further refinements to its approach for a utility of its size.

3.2.3.1 Findings

[53] The Board is sensitive to the utility's concern about the trade-offs associated with the pursuit of precision in the analysis used in rate studies for a very small utility. It could increase the costs and time associated with developing a rate application for little or no benefit. While BEC did not really explain how Mr. Havumaki's suggested approach would cause such concerns, given the nominal results of the confidential sample calculation provided by Mr. Havumaki, the Board declines to direct BEC to undertake the more refined analysis recommended by Mr. Havumaki at this time. However, the utility should periodically assess whether its more simplified approach results in an unreasonable shifting of costs between rate classes.

3.3 Rates and Charges

3.3.1 Revenue-to-Cost Ratios

[54] Exhibit B-1 (Exhibits 5 and 6) set out calculations showing a revenue shortfall in 2023 of $1,014,552, calling for an overall average rate increase of 17.9% to satisfy BEC's proposed revenue requirement. Under existing rates, BEC's cost of service analysis shows that all rate classes are under-recovering revenue, except for the small general service class, which was within the 95% to 105% revenue-to-cost range the Board considers to be reasonable. Street lighting was shown as recovering less than half of the costs of providing that service.

[55] To address the shortfall in revenue under current rates, BEC proposed the following:

a. Unmetered lighting rates would increase by 150% of the system average increase but would still only fall at a revenue-to-cost ratio of approximately 60%.
b. Industrial rates would increase by approximately 24%, which would be above the system average increase and produce a revenue-to-cost ratio of approximately 100%.
c. Small general and general service class rates would increase to a revenue-to-cost ratio of approximately 105%.
d. Remaining rate classes would increase proportionately to recover the remaining revenue deficiency producing revenue-to-cost ratios within the Board's 95% to 105% range.

[56] The utility referred to the Board's decision on Mahone Bay's recent general rate application to support its proposed unmetered lighting rate increase. In that case, the Board considered a similar issue, where street lighting rates were substantially

under recovering based on the results of the cost-of-service study. Mahone Bay had proposed a proportionate increase for this rate class, but the Board accepted the recommendation of Melissa Whited (Synapse) to impose a greater increase, limited to 125% of the system average to balance gradualism and rate shock.

[57] The Board observes that BEC has proposed a proportionately larger increase in this proceeding (150% compared to 125%), but given the larger system average increase in the Mahone Bay application, the result in that case was an approximate 38% increase in the street light rate (phased in over two years). In the present case, the proposed rate increase at 1.5 times the system average is 26%.

[58] Mr. Havumaki recommended that the Board set aside the usual concern about gradualism as it relates to bringing the lighting class into the Board accepted revenue-to-cost range. He said that lighting class customers are different from customers in other rate classes. He said this raises different considerations around the concept of “rate shock.”

[59] At the hearing, the Board asked Mr. Regan about Mr. Havumaki’s recommendation. Mr. Regan confirmed that most of the lighting revenue is paid by the Town of Berwick or the County and, while he appeared to accept Mr. Havumaki’s proposition, he noted that the streetlight rates are not negligible:

> Q. Mr. Regan, I’m going to aim this one at you, but you can deflect it any way you like.
>
> Synapse suggests that gradualism is not necessary for some of the lighting class. Could you comment on that?
>
> A. (Regan) I would say that what they were referring to there would not -- the absolute dollar amounts are not huge, but they’re not negligible, either. But we could accept that.
>
> Q. And in in IR response -- I don’t think we need to pull it up -- I think we were advised that the Berwick Electric Commission owns all of the street lights?
>
> A. (Regan) That’s correct.

> Q. And so who pays the street light rates?
>
> A. (Regan) Largely the Town of Berwick. We rent a few to the county as well.
>
> Q. Okay. And ---
>
> A. (Regan) And I distinguish between street lights and yard lights, obviously.
>
> Q. Okay. And yard lights, are they owned by private individuals or are they owned all by Berwick Electric Commission as well?
>
> A. (Regan) They're owned by Berwick Electric Commission. We would have a few signs and light fixtures that we supply power to for customers that are customer owned.
>
> Q. Is that just a small number of that situation? Would the rest be something that you would charge to the municipality or the town?
>
> A. (Regan) That is a relatively small number, yeah.
>
> [Transcript, pp. 95-97]

[60] As discussed in more detail below, the Board finds that a larger increase than proposed for the lighting class is appropriate in the circumstances of this case.

[61] The utility justified its proposed above-average increase to industrial rates on the basis that the industrial class presently has a revenue-to-cost ratio significantly lower than other non-domestic metered classes. In its response to Board IR-47(b), BEC said it would prefer to see relatively consistent revenue-to-cost ratios among its metered non-domestic customers, if this can be achieved with rate adjustments in a reasonable range, but it was not opposed to a lower adjustment for the industrial class at this time. The Board concludes that a more proportionate rate increase is appropriate.

[62] The Board understands the utility's proposal to set the small general and general service rates at a revenue-to-cost ratio of 105% recognizes that a proportionate increase would produce results for those rate classes that would exceed the top end of the Board's generally accepted range. The Board considers the utility's approach to be appropriate in the circumstances of this case.

3.3.1.1 Findings

[63] The Board has concerns about the substantial under recovery of costs through the lighting rates. The Board recognizes that the utility shares that concern, as evidenced in its proposal for a greater increase in the proposed rates for this class. The Board partially accepts Mr. Havumaki's recommendation, to the extent that it urges a greater increase for this rate class due to its nature, but fully accepting the recommendation to increase cost recovery to within the Board's generally accepted range of 95% to 105% would, in the Board's view, be inconsistent with the approach recently taken in similar circumstances in Mahone Bay's general rate application.

[64] The Board directs that the rates for the lighting class be increased by 175% of the system average rate increase. While the factor of 1.75 times the system average is much larger than the 1.25 factor applied in Mahone Bay's case, in absolute terms, the percentage increase resulting from the application of these factors will be smaller than the approximately 38% increase in Mahone Bay's lighting rates. The factor could be increased further and the resulting percentage increase would still be below the Mahone Bay increase. That said, Mahone Bay's rate is being phased in over two years, while the rate increase in this application will occur at once.

[65] After the lighting class increase discussed above, and the rates for the small general and general service classes are increased to produce a revenue-to-cost ratio of 105%, the rates for the remaining classes should be increased proportionately to make up the remaining revenue deficiency. The Board does not believe it is appropriate to selectively increase one rate class more than the others in the circumstances of this case, where proportionate increases for those classes would land them in the 95% to 105% revenue-to-cost ratio range.

[66] Based on the rate study filed in this proceeding, the Board believes that this will result in all rate classes landing within the Board's 95% to 105% revenue-to-cost range (except for the lighting class), although certain directions in this decision could vary that to some extent. To be clear, the proportional rate increases should only be applied to increase a rate class up to a 105% revenue-to-cost ratio. If a rate class reaches that point, recovery of any further revenue deficiency must be from rate classes that continue to be below 105%. Similarly, if a rate class remains below a 95% revenue-to-cost ratio after following this methodology (except for the lighting class), that rate class should be increased to 95% and the revenue responsibility of the remaining rate classes (excluding the lighting, small general and general service classes) should be reduced proportionately so long as they are above a 95% revenue-to-cost ratio.

[67] Overall, the Board considers this approach to be like what BEC proposed, except for the larger increase for the lighting class and the rejection of BEC's proposal to set industrial rates based on a revenue-to-cost ratio of 100% (under the approach directed by the Board industrial rates will be at least at a 95% revenue-to-cost ratio).

3.3.2 Domestic Customer Service Charges

[68] In its decisions on the RELC and Mahone Bay rate applications, the Board accepted Synapse's recommendation to set the utilities' domestic customer service charges based on customer-related costs in the cost-of-service study rather than to apply the same percentage increase to the customer service and energy charges. This resulted in smaller customer charge increases than proposed in those cases.

[69] In its application, BEC acknowledged the precedent set in those cases but noted that its existing domestic service charge of $20.19 per month appeared to have

been set on a different basis in its last rate application. In response to Board IR-49, BEC noted that using the method directed by the Board in the RELC and Mahone Bay cases would result in a customer service charge of only $7.73. In the circumstances, BEC proposed to keep its service charge at its current rate.

[70] Mr. Havumaki acknowledged concerns about reducing the customer service charge from approximately $20 to less than $8 in his evidence, but noted if the service charge is recovering non-customer related costs, it artificially reduces variable energy rates and tends to make customers consume more than the socially optimal amount of energy. He said it also results in smaller customers subsidizing larger ones and has implications for investing in efficiency and conservation measures. Still, rather than fully reduce the rate, Mr. Havumaki recommended setting it at $13 per month, which is the approximate rate that was set in the RELC and Mahone Bay cases.

[71] At the hearing, Board Counsel asked BEC's witnesses why they disagreed with Mr. Havumaki's recommendation:

> Q. Okay. And so I would like to hear from the panel as to why it is that the -- setting the rate at the $13, for instance, as proposed by Synapse -- why that's a recommendation that the panel -- that BEC is not prepared to accept?
>
> A. (Regan) I think we differ in philosophy somewhat with Synapse on the question of what's an appropriate customer charge. We always included some larger slice of fixed costs in that charge than is their philosophy.
>
> In the -- the nature of -- the ways in which people take service is changing. Slowly, but it is changing. With time of use metering and with net metering, the service charge is, really, in my view, regarded as access to the system. Whatever use you want to make of the system -- and they keep changing uses, and there will probably be ones I haven't thought about yet -- that connection gives them the capability to do that.
>
> Q. Ms. Zarnett or Mr. Winstone, do you have any comment on this topic?
>
> A. (Zarnett) I'll make a couple.
>
> I think in recommending $13 as the charge, probably the consultant was referencing approximately amounts that were for Mahone Bay and Riverport in the recent hearing.

I'd just like to point out that for those utilities, that was still an increase over the prior level. It was not a 30 percent decrease, which it would represent here for Berwick. And some other jurisdictions are now starting to consider that, in fact, even though they're not so-called customer charges, the demand-related components of distribution costs are fixed in the medium in short term and, therefore, changes in consumption by customers don't remove from the cost base of the utility any costs.

So for instance, as Mr. Regan stated, uses are changing. Customers that have self-generation or net metering would then reduce their take from the system and would not necessarily contribute their fair share in costs of the distribution system under those scenarios. So as a result, in some places the philosophy is changing to regard all the distribution costs as being subject to recovery through a fixed charge.

So that's an area of judgment for each jurisdiction and each regulator, but it is a trend that does exist.

And I guess finally, I'd just like to say that reducing that charge would put more burden on the energy charges and that means particularly bill increases in winter when those are of particular concern to a domestic customer.

Q. Other than that issue, Ms. Zarnett, do you see any other negative impacts associated with moving the customer charge to the level recommended by Synapse?

A. (Zarnett) I guess to add also -- I guess with 13, there is some cushion against, I guess, what might be the future level of the charge on a customer basis only. If, for instance, the utility had to make significant investments in assets that are classified as customer, for instance, interval metering, particularly meters and services, or there was a reclassification, in Berwick's case some of the -- some of the results of that classification are the result of the mix of assets that Berwick has on its distribution system at present.

They're very heavily weighted in terms of transformers, which have been classified as 100 percent demand. If there was any change in that methodology, it would shift that classification significantly in the direction of customer.

Q. Ms. Zarnett, do you accept that, on the positive side of moving the customer domestic charge to $13, that there are certain benefits that accrue from making that charge more related to the actual cost of serving the customer?

A. (Zarnett) I'm of the school that thinks that all the -- all the distribution costs are related to serving the customer and are not variable with consumption, so I would say no. However, I understand that another view is a matter of judgment.

[Transcript, pp. 22-26]

3.3.2.1 Findings

[72] The Board accepts BEC's proposal to keep its domestic service charge at its current rate. While the Board still considers that the customer service charge should recover customer related costs, it accepts Ms. Zarnett's comments, to the extent that there are trends in the industry, driven by changes in technology, costs and the need to

transition energy systems to meet government established net-zero targets, that may warrant different considerations in the not too distant future. Additionally, to Ms. Zarnett's comment about the impact of investments in assets classified as customer related, as the Board noted above, BEC intends to convert to smart meters over a two-year period in fiscal years 2024-25 and 2025-26. If the circumstances mentioned by Ms. Zarnett occur, sharply reducing the customer charge now, which was not required in either the RELC or Mahone Bay cases, might soon be followed by an increase in the future. This could impact the principle of rate stability. Given the significant rate increases being approved in this decision, the Board considers it would be better to keep the components of rates more stable where this is possible, rather than risk confusing customers by having some charges significantly reduced while others are significantly increased.

[73] Notwithstanding the Board's decision on this point, the Board directs BEC to provide as much detail as possible to support any departure from the approach adopted by the Board in its decisions in the RELC and Mahone Bay cases in its next general rate application.

3.3.3 Time of Use Rates

[74] BEC was not able to provide support, either historic or in the current application, for the cost basis of its optional domestic and general demand time of use charges. Currently, only domestic customers use the optional time of use rates. BEC observed that the shoulder rate for its domestic time of day prices appeared to be set at the regular domestic energy rate. The peak charge was nearly 85% more than the shoulder rate. The off-peak rate was nearly 30% lower than the shoulder rate. BEC therefore proposed the following for its domestic time of day rates:

- Shoulder rate equal to the energy charge applicable to non-TOD Domestic consumption.
- Peak rate equal to 1.85x the shoulder rate.
- Off-peak rate equal to 0.70x the shoulder rate.

[75] The Board assumes the intention was to maintain the current service charge of $23.19 per month, but this can be clarified in the utility's compliance filing.

[76] BEC noted that its calculations show that the off-peak rate will be enough to recover its cost of purchased energy at NS Power's wholesale rate to municipal utility customers, including losses at 4.3%, and therefore the rates in all TOD rating periods will contribute to the recovery of BEC's costs to deliver supply to the customers.

[77] BEC proposed no changes to its other optional rates but anticipates revisiting the need for these rates in the future.

3.3.3.1 Findings

[78] The Board approves BEC's proposal for its optional time of use rates and directs the utility to further assess the cost basis and reasonableness of these rates in its next general rate application.

3.3.4 Small General Service Declining Block Rate Structure

[79] BEC currently has a declining block rate structure for its small general service class. The utility proposed to end this rate structure in this application and move to a single energy charge for this class. It said this request was based on its understanding that most jurisdictions no longer consider declining block structures consistent with rate design objectives and its preference for a simpler rate for the customers.

[80] BEC advised that it performed a preliminary test of the bill impacts from this change. It provided this analysis in response to Board IR-50. The results of this analysis suggest that customers who consume less than the class average would experience decreases from this change, while customers with above average consumption would experience increases. A customer with a bill for 1,200 kWh (nearly double the class average) would experience a 5.7% increase.

[81] BEC said it considered the timing of this request in the context of the rate increase proposed in this proceeding. It noted that the proposed increase for this rate class was limited to rates set to recover at a revenue-to-cost ratio of 105%. Therefore, even with the change to the rate structure, no customers in this class would be likely to experience a bill increase more than that being experienced by metered customers in other classes.

3.3.4.1 Findings

[82] The Board approves BEC's request to end the small general service class declining block rate structure. The Board notes that the rate study BEC filed did not account for this change and BEC is directed to provide updated schedules based on this approval.

3.3.5 Off-peak Charging Rate

[83] BEC has an off-peak charging rate approved by the Board in September 2021 (M10179). This rate was not addressed in the utility's rate study but in response to Board IR-19, the utility noted it should be included in this proceeding, with an increase consistent with any increase the Board approves for the domestic class. At the hearing,

the Board questioned how the off-peak charging rate would be set under the proposed tariff, which the utility agreed to address in an undertaking.

[84] In its response Undertaking U-9, BEC clarified its current proposal and its intention to undertake further analysis about this rate:

> As noted in response to Board IR-19, the existing energy charges for the Off Peak Charging Rate, as approved by the Board in its Order dated October 18, 2021, are $0.1405 per KWH for energy delivered between 6:30AM and 12:00AM and $0.1076 per KWH for energy delivered between 12:00AM-6:30AM.
>
> BEC's intent in the current Rate Application is that the energy charges under the Off Peak Charging Rate for energy delivered both on and off peak be increased by the same percentage as the Domestic energy rate, and the service charge be treated the same as the Domestic energy rate.
>
> As indicated by Mr. Regan during the hearing, BEC intends to consider whether the rate should be redesigned to ensure it is working as intended now that BEC has had initial experience with the rate with one customer. BEC will include this analysis of the Off-peak Charging Rate as part of its next General Rate Application.
>
> [Exhibit B-11, Undertaking U-9]

[85] The Board observes that the current service charge for this rate is the same as the domestic time of day rate, not the domestic rate.

3.3.5.1 Findings

[86] The Board approves BEC's proposal, as set out in Undertaking U-9, and directs BEC to clarify its proposed service charge for this class of service in its compliance filing.

3.3.6 Streetlights and Yard Lights

[87] During this proceeding, it became apparent that the rate study included lights that were no longer in use by the utility. At the hearing, the Board asked the utility to update the schedules in its rate study with proposed rates for the lights that are actually in use.

[88] The utility's response to Undertaking U-8 included a listing of active streetlights and active yard lights. BEC advised, "In terms of the specific rates to be approved for these lights, BEC anticipates this can be addressed in the Compliance Filing following the Board's decision confirming the revenue and cost allocation by class, so it will include only the fixtures shown here and reconcile any discrepancies between like fixtures."

3.3.6.1 Findings

[89] The Board directs that the proposed rates for the lights be addressed in BEC's compliance filing.

3.3.7 Demand Side Management Costs

[90] BEC proposed to add a separate rider to recover NS Power charges for its Demand Side Management Cost Recovery Rider. However, in its opening statement at the hearing, BEC withdrew its request to add a DSM rider as a separate line item on its bills, and instead proposed to make the necessary adjustments to take this into account in its compliance filing. This change was intended to make its request consistent with the Board's decisions in the recent RELC and Mahone Bay rate applications.

3.3.7.1 Findings

[91] BEC is directed to update, in a compliance filing, its proposed rates to account for DSM charges as noted in its opening statement.

3.3.8 Phasing-in the Rate Increase

[92] As noted earlier in this decision, BEC's application proposed a 17.9% overall average rate increase. BEC acknowledged the magnitude of this increase in its opening statement:

> Finally, with respect to the overall rates requested in the Application, BEC appreciates that the magnitude of the 17.9% increase is significant for its customers. However, deferral of any of the increase would attract additional financing costs that would eventually need to be borne by customers. BEC is already concerned about the magnitude of the growing obligation to repay unrecovered fuel costs through NS Power's Fuel Adjustment Mechanism as a result of its return to service under the Municipal Tariff in 2023. In light of the Board's decisions in the General Rate Applications of the Town of Mahone Bay and the Riverport Electric Light Commission earlier this year capping annual rate increases for these municipal electric utilities at 20%, BEC requests approval in full of the rates as requested in the Application.
>
> [Exhibit B-7, p. 2]

3.3.8.1 Findings

[93] As the Board discussed in *NS Power 2023-2024 Rate Application* (2023 NSUARB 12), there are trade-offs involved with using deferrals to phase in rate increases, as they often result in higher costs in the longer term. This must be balanced against the rate-setting principle that rates should be stable, and experience minimal unexpected changes that are seriously adverse to existing customers.

[94] In assessing this balance, the Board determined it was appropriate to phase in the rate increases approved in RELC's and Mahone Bay's recent applications, but the approved increases were larger in those cases than the overall average increase in this proceeding. As noted by BEC in its opening statement, the initial year for this phase in was capped at a 20% increase, which is more than BEC's system average increase.

[95] Also, the Board recognizes BEC's concern about pushing unrecovered costs into a future period when this may only compound future rate increases that could also be significant. In this regard, the Board notes the likelihood that under-recovered fuel costs will be added to BEC's purchased power cost through NS Power's fuel adjustment mechanism.

[96] In these circumstances, the Board concludes that BEC's approved rate increase should be implemented at once. This will be a hardship for many, but deferring

the utility's recovery of the costs it is incurring is both difficult for a smaller utility to manage and likely to create more significant problems in the future.

3.3.9 Pole Attachment Charge

[97] BEC requested approval to increase the rate it charges to telecommunications carriers to attach their equipment to poles owned by BEC. The proposed charge of $22 amounts to an increase of $7.85 or nearly 55%.

[98] For years, BEC maintained a pole attachment charge of $14.15, the same rate charged by NS Power before its last general rate application. BEC explained that it aligned its proposal for the fee increase with the pole attachment fee negotiated in the settlement agreement proposed between NS Power and communications companies in *NS Power 2023-2024 Rate Application*, for the rate of $22.00 per year with annual cost escalations of 2%. The same approach was approved by the Board for RELC and Mahone Bay in their recent general rate applications.

3.3.9.1 Findings

[99] The Board observes there were no interventions or challenges to BEC's proposed pole attachment charge. The current charge has been in effect since 2003 and the evidence indicates that the utility is not recovering its costs from the current fee level.

[100] Shortly before the hearing in this matter, the Board released its decision in *NS Power 2023-2024 Rate Application* and approved the proposal for NS Power's pole attachment charge of $22.00. The Board is satisfied that the proposed pole attachment charge represents a fair and reasonable estimate.

[101] The Board approves the pole attachment charge of $22/pole/year, and the related amendment to Schedule B – Schedule of Rules and Regulations (Regulation

33). However, in response to Board IR-56, BEC advised it would amend the proposed changes so that the rates for 2023 and 2024 are specified, rather than identified as a formula and it is directed to make this change in its compliance filing.

3.3.10 Inspection Fees

[102] BEC proposed to increase its electrical inspection fees to match those recently approved by NS Power. No issues were raised about the request in this proceeding.

3.3.10.1 Findings

[103] In BEC's last application the Board approved a similar request and concluded it was reasonable for BEC's charges to be in line with NS Power's. Likewise, the Board approves BEC's current request.

3.4 Future Studies and Proceedings

3.4.1 Factorydale Hydro Facility

[104] BEC filed information about studies and work done on its Factorydale watershed structures in its responses to Board IR-15 (Exhibits B-4 and B-4(i)) and Undertakings U-2 and U-10 (Exhibit B-11). This information included a Dam Inspection & Flood Inundation Assessment dated June 2006, an Emergency Preparedness Plan dated July 2007 (which appears to have been updated to March 2011), a Report and Recommendations on the Penstock and Surge Tank dated July 2012, and correspondence about recommendations for work on the penstock in July and September 2015.

[105] At the hearing, Mr. Regan said that the Factorydale dam structure has been significantly reinforced since the 2006 study, and that work was done on the

penstock and storage dam upstream. After consulting the Canadian Dam Association, the utility noted in its response to Undertaking U-10 that a dam safety assessment should be carried out every 5 to 10 years and if there is a significant change that has important dam safety implications.

[106] The utility said it intends to commission a review study of Factorydale before its next general rate application. In response to Board IR-14(d), the utility noted that the timing of its next application remains to be determined and it could be filed in 2024 if the utility expects that the rates approved in this decision will not recover its forecasted revenue requirement in 2025.

[107] The Board directs the utility to undertake a dam safety assessment and update its emergency preparedness plan before it files its next general rate application, or before December 31, 2024, whichever is earlier. The dam safety report and an updated emergency preparedness plan must be filed with the Board upon completion.

3.4.2 Flow-through Applications

[108] BEC's current tariffs include mechanisms that allow it to update its rates in an expedited fashion to recover increased costs due to NS Power rate increases and changes in NS Power's fuel adjustment mechanism and demand side management riders. These mechanisms were developed several years ago and, since that time, the wholesale resource arrangements by municipal electric utilities have expanded. At the hearing, Mr. Regan agreed that these mechanisms are no longer ideal as they were originally designed, and other mechanisms may be more appropriate in the current circumstances. Mr. Regan also agreed that it would be appropriate for the municipal electric utilities in the province to discuss potential alternative mechanisms.

[109] The Board encourages BEC to consult with the other municipal electric utilities in the province about the development of flow-through mechanisms that may be more appropriate in the circumstances. While not intending to pre-judge the outcome of these discussions, the Board observes that the existing flow-through mechanisms are designed to recover costs imposed on the municipal electric utilities by NS Power and involved rates the Board would have considered and approved for NS Power. As such, questions about the prudence of the recovery of these costs by the municipal electric utilities would not really have been an issue. To the extent that any future mechanism that might be proposed by BEC includes costs other than those tied specifically to NS Power's Board-approved rates, the mechanism would likely need to include a process to ensure that only prudently incurred costs are passed along to the utility's customers.

3.4.3 Municipal Electric Utility Rate Application Guide

[110] In its opening statement at the hearing (Exhibit B-7), BEC responded to some of the cost allocation concerns raised by Mr. Havumaki by stating that it felt there was "a balance to be struck between precision and the need for further refinements that are appropriate for a utility of its size." The Board also observes that other aspects of the utility's rate application, such as the classification of distribution system costs, pole attachment charges, inspection fees, and working capital relied on historical practices in Nova Scotia and Ontario. Additionally, BEC pursued a more formal return on equity in this proceeding but did not file supporting evidence that was as comprehensive as the Board would typically expect from larger investor-owned utilities, such as NS Power or Eastward Energy.

[111] In response to a question from the Board at the hearing, Mr. Regan agreed that it may be worthwhile to develop some sort of filing guidelines or requirements that could outline some “rules of thumb” or established practices that could be followed by municipal electric utilities when filing general rate applications (if they wished), like the Board’s *Water Utility Accounting and Reporting Handbook*. If, upon consultation with the other municipal electric utilities in the province, it is concluded this would be worthwhile, the Board would invite the municipal electric utilities to raise this with Board staff.

4.0 SUMMARY

[112] The Board approves the proposed changes to BEC’s Schedule of Rates for Electric Supply and Service and its Schedule of Rules and Regulations Governing the Supply of Electric Services, effective the date of this decision, subject to the following:

- The cost of debt used to determine the revenue requirement will be 3%.
- The unmetered lighting rates will be increased by 175% of the system average increase.
- The rate increase for the industrial class will be determined proportionately, as described in Section 3.3.1 in this decision.

[113] BEC is directed to file a compliance filing, no later than December 11, 2023, to address the changes to its application required by this decision; the recovery of DSM through existing charges rather than a separate rider; the removal of the declining block rate structure for the small general service class; identify specific streetlight and yard light rates; and to clarify the proposed service charges for its domestic time of day rate and its off-peak charging rate . The compliance filing must include updated versions, in excel format, of its application exhibits (Exhibits 1-1 to 7) in Exhibit B-1. The compliance

filing must also include clean and redlined versions of the utility's new tariffs and regulations.

[114] BEC is further directed as follows:

- In its next general rate application, BEC must:
    - update the Board about its ability to determine class coincident and non-coincident peaks and the accuracy of the peaks determined for its general service class;
    - assess the cost basis and reasonableness of its time of use rates.
- BEC must undertake a dam safety assessment and update its emergency preparedness plan before it files its next general rate application, or before December 31, 2024, whichever is earlier. The dam safety report and an updated emergency preparedness plan must be filed with the Board upon completion.

[115] An Order will issue accordingly.

DATED at Halifax, Nova Scotia, this 24th of November, 2023.

Stephen T. McGrath

Jennifer L. Nicholson