DECISION | **2024 NSUARB 79**
M11441

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF AN APPLICATION by the **TOWN OF ANTIGONISH, on behalf of its Electric Utility,** 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: Richard J. Melanson, LL.B., Member, Panel Chair
Steven M. Murphy, MBA, P.Eng., Member
Bruce H. Fisher, MPA, CPA, CMA, Member

APPLICANT: **ANTIGONISH ELECTRIC UTILITY**
James MacDuff, Counsel
Lucia Westin-Eastaugh, Counsel

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

HEARING DATE: March 26, 2024

FINAL SUBMISSIONS: April 11, 2024

DECISION DATE: **May 9, 2024**

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

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1.0 INTRODUCTION

[1] The Town of Antigonish, on behalf of its electric utility, applied to the Nova Scotia Utility and Review Board to amend its rates for electric supply and services. Citing a significant increase in the cost of its purchased power, and additions to administrative and general expenses, the Utility requested that average rates be increased by 7.2% to 7.9%, depending on the rate class. This request requires an increase of 6.29% in revenue from its customers. The Utility's Large General Rate is equal to the NS Power rate for the same rate class, which increased on January 1, 2024. The Utility is also seeking increases in its pole attachment fees.

[2] The Utility's last general rate application (GRA) appears to have been in the 1980s. The Utility has been able to function without a general rate application due to consistent growth of its load and customer base, its ability to control costs, and due to the flow-through mechanism, that allows the Utility to pass along increased costs of purchased power from NS Power.

[3] On March 26, 2024, the Board held a public hearing in the Town of Antigonish Council Chambers. The hearing was also live-streamed. Meaghan Barkhouse, Director of Finance for the Town of Antigonish, 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. The Utility's consultants, Paula Zarnett and Trent Winstone, of BDR North America Inc., appeared virtually. Board Counsel consultant, Melissa Whited, of Synapse Energy Economics, Inc., also testified virtually.

[4] In its application and during this proceeding, the Utility claimed confidentiality over certain information filed with the Board. The Board accepts the confidentiality claims.

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

2.0 BACKGROUND

[6] The Antigonish Electric Commission is owned by the Town of Antigonish and operates as an electricity distribution utility. The Utility serves approximately 3,756 metered customers in the Utility's service area and also includes 781 unmetered streetlights. The Antigonish Electric Commission is the largest of the municipal electric utilities operating in Nova Scotia. In recent years, the Utility's service area has experienced modest growth in its customer base and total energy sold.

[7] The Utility operates the distribution system and currently supplies its customers with energy produced by the Ellershouse Wind Farm, under a contract through AREA, and from Nova Scotia Power Incorporated (NS Power) under its Board-approved tariff for municipal electric utilities.

[8] The Board approved the Utility's rates in the 1980s, with the most recent rates based on a flow-through application approved effective January 1, 2024. The Utility says it requires a rate increase because of escalating costs, especially the cost of purchased power and additions to administration costs. The Utility advised that AREA, on its behalf, entered negotiations for its wholesale supply of electricity, in the context of the serious escalation of fuel prices in world markets. The Utility said that, after evaluating several alternatives, it has decided to take supply from NS Power. Based on NS Power's Board-approved rates, the costs of the Ellershouse Wind Farm power, and forecasted loads, the Utility's cost of purchased power will increase by approximately 31% in 2024/25 over 2022/23.

[9] Due to increased load and the recently approved NS Power flow-through rates, the Utility forecast a revenue increase of 22% for the test year, compared to the 2022/23 revenues. While the increase in projected revenue is strong, it only covers a little more than two-thirds of the total increase in revenue requirement.

[10] Although the Utility had large operating surpluses over the last several years, it projects an operating loss for the 2023/24 financial year and a loss of $670,043 in the test year at its current rates. The Utility has concluded that it cannot continue to provide service at its currently approved rates without negatively impacting its financial integrity. As filed, the general rate application proposes an overall increase in its revenue from its customers of 6.29%. This would result in rate increases ranging from 7.2% to 7.9% for all rate classes other than large general, which has its rate set at the NS Power rate for the same rate class.

3.0 DISCUSSION AND ANALYSIS

3.1 Revenue Requirement

[11] The Utility is requesting approval of a revenue requirement of $15,521,719 for the 2024/25 test year. This includes the total cost of purchased power, operations and maintenance costs, administrative and general costs, depreciation and amortization, plus $253,789 for a proposed return on rate base of 6.1%. Aside from the return on rate base, the Board finds the revenue requirement for the test year is reasonable, subject to the adjustments made in this decision.

3.1.1 Purchased Power Costs

[12] In the test year, the Utility expects to be supplied power from energy produced by the Ellershouse Wind Farm under a separate wind contract through AREA,

and energy purchased from NS Power under its Board-approved tariff for municipal electric utilities. The Utility forecasted its purchased power cost in the test year, and its weather-normalized electricity sales to serve its customers, including system losses of 2.2%. Purchased power is the largest component of the Utility's total operating costs and is forecast to increase by approximately 32.7% over 2022/23, representing the most significant component of the Utility's increased revenue requirement for the test year.

[13] AREA is an inter-municipal agency that procures all power supply for the Utility, as well as for other Nova Scotia municipal electric utilities. Considering the serious escalation of fuel prices over the past several years, AREA sought new arrangements for the Utility's wholesale supply of electricity. After evaluating several alternatives, the decision was made to change suppliers and purchase power from NS Power. The Utility 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 current and test year.

[14] Mr. Winstone noted that the 2.2% distribution system losses were calculated from historical data supplied by the Utility. Some of the data showed negative line losses for some periods. During questioning, Mr. Winstone agreed that 2.2% was low and quite a bit lower than Riverport, Mahone Bay, and Berwick's (other Nova Scotia municipal electric utilities) line losses. Ms. Whited was concerned about the frequency of the negative values. In her opinion, distribution system losses of 4% to 5% would be more representative.

[15] Mr. Winstone also explained that the line losses were calculated by looking at power purchased relative to bills over the same time period. One issue with this analysis is that the dates on which the Utility is invoiced for purchased power does not

align with billing dates to Utility customers. In theory, this lag would catch up over time, but this does not appear to be the case with the line loss data.

[16] In the Utility's calculation for off-peak demand for the Time-of-Day rate class, it based the rate on NS Power's Municipal rate, with 4% added for potential line losses, as opposed to the 2.2% distribution losses used elsewhere in the rate study.

3.1.1.1 Findings

[17] The Board considers the estimated purchased power costs to be reasonable, other than the calculated amount of system line losses. The Board agrees with Board Counsel's consultant that the system losses at this level are much lower than what would be expected for the average utility.

[18] The Board directs the Utility to recalculate its forecast purchased power costs using line losses of 4% in a compliance filing.

3.1.2 Administrative and General Expenses

[19] The Utility forecasts its administrative and general expenses for the test year using the amounts from its 2023/24 budget (fiscal year ended March 31, 2024) but with an inflation increase of 3% added to most cost categories. The 2023/24 Budget was significantly higher than the prior year ending March 31, 2023. The largest of the increases is in Operating and Maintenance expenses (30% increase). In addition to this line item, the Town Administration charges to the Utility, which form part of the Administrative and General expenses, increased by almost 63% from 2020/21 to 2021/22. This increase was sustained up to and including the test year.

[20] The Board had several questions about the allocation of common and shared costs attributed to the Town's utilities (including both the electric and water utilities). The Utility noted that these cost categories' increases were driven by higher

wages and allocating a larger portion of the Town's shared costs to the Utility, to better reflect the time and effort by Town staff spent on Utility-related work.

[21] The Utility noted that the shared allocation percentages are reviewed periodically, most recently in preparation for this application. The allocation of administrative salaries and other shared expenses has been updated to better reflect the support provided. This resulted in a large increase in the administrative charge from the Town to the Utility.

[22] In response to Board staff Information Requests (IRs), the Utility explained that the increase in operations and maintenance expenses was due to an increase related to maintaining poles, distribution services, and tools. The Utility further noted that these were not one-time increases, but annual costs required to maintain operations at the current level.

3.1.2.1 Findings

[23] Although some of the cost category line items have increased well above the rate of inflation over the last several years, the Board finds that the forecast administrative costs appear reasonable, given that a portion of the increase is related to updated allocations of shared Town costs.

[24] The Board notes that for the past number of years, the Utility's operating costs have been stable, which is a surprise given the inflationary environment over that period. This stability in costs appears to have led to several years with rather large rates of return on the Utility's assets. If the allocations provided for the test year were in place over the last several years, the Board understands that the returns realized by the Utility would have been lower than reported.

[25] The Board encourages the Utility to continue to be diligent in controlling its operating costs as it has been over the past several years or more. The Board further encourages the Utility to monitor, and frequently review, the allocation percentages for shared Town costs, to ensure that only prudently incurred expenses for the Utility are being allocated to the Utility.

3.1.3 Depreciation Expense

[26] In Exhibit 1-2 Net Plant (Exhibit A-1(ix)), the Utility calculated its depreciation expense for each class of its assets. This resulted in a total depreciation expense of $319,524 for the test year. Depreciation expense for the test year was calculated by applying the Utility's amortization rates to existing assets and on projected new assets in rate base.

[27] During the hearing, there was some discussion on the depreciation expenses allocated to particular asset classes. When questioned by the Board, Ms. Zarnett indicated that there were discrepancies in several individual asset class accounts, but the total depreciation expense was only off by two dollars. As a result of that discussion, the Board directed the Utility, by way of an undertaking (U-4), to re-submit Exhibit A-1(ix) to correct depreciation expenses in Exhibit 1-2 and any other worksheet that was based on that exhibit.

[28] In Undertaking U-4, the depreciation expense for the test year was revised to $319,522. In addition to the slight change in total depreciation expense, several asset classes had significant changes from the amounts in the original filing. Nonetheless, these changes in amounts largely offset one another.

[29] Although the resulting allocation of depreciation expenses, as well as the ratio of revenue to costs, were impacted, the Utility suggested that there was not enough

of a change to any of the rate classes to amend its recommended rate increases for any of the rate classes due to depreciation expense allocations.

3.1.3.1 Findings

[30] The Board accepts the Utility's amendments to the asset categories depreciation expenses for the test year, as provided in Undertaking U-4 with the updated total depreciation expense of $319,522. The Board directs the Utility to incorporate the corrections set out in Undertaking U-4 in its compliance filing.

3.1.4 Capital Costs

[31] The Board approved the Utility's Grid Modernization Project on December 15, 2023. This project is planned in phases over several years. Phase I is a new substation and 25kV circuits. Phase II involves modifying an existing substation. Phase III involves deploying smart meters. Although the Utility has spent funds related to the upcoming Grid Modernization Project, these costs are not being capitalized or depreciated in the test year. The Utility did, however, propose to capitalize the cost of the rate study associated with this GRA and amortize it over two years, one of which is the test year. Based on Exhibit A-1(ix) tab Exhibit 1-1, the only other proposed capital costs in the test year are $29,662 for street lighting and $10,948 for services.

3.1.4.1 Findings

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

[33] The Board notes that the Utility is planning a large Grid Modernization Project, which has already been approved by the Board. As noted by the Utility, spending on this project will be included in rate base and amortized in a future rate application.

3.1.5 Working Capital

[34] The Utility requested approval of a working capital allowance of $1,494,841. This amount is based on an estimated 36-day bill payment lag (10%) applied to its forecast of $14,948,405 in net cash expenses (cost of purchased power, operations and maintenance, and administrative costs, but excluding amortization). The Utility has chosen not to request a further working capital allowance for inventory.

[35] A 2009 report from Stantec, used to establish the Utility's rate base at that time, said that working capital should consider average monthly inventory and customer deposits. In Undertaking U-2, the Utility provided the average monthly value of its inventory on hand as well as its average monthly customer deposits. The monthly average inventory was valued at $1,080,471 as of March 31, 2023. Customer deposits on the other hand, only averaged $350.22.

[36] The Utility has not performed a lead-lag study. Instead, it submitted that the estimate of a 36-day lag was made based on default factors and rules of thumb used elsewhere, primarily Ontario. This methodology was accepted by the Board in the Berwick Electric Utility's (BEC) most recent GRA. The Utility noted the amount requested is slightly higher than what is seen in Ontario because its Domestic customers, which make up about 40% of revenues, are billed bi-monthly, as opposed to monthly. For utilities with advanced metering infrastructure (AMI) meters and monthly billing, the requirements for working capital are lower. The Ontario Energy Board generally uses 7.5% for utilities that do not conduct lead-lag studies.

[37] The Utility's requested amount of working capital makes up approximately 36% of the Utility's total rate base, which will be discussed later in this decision. The Utility noted that current rates have no specific allowance for working capital embedded in them.

[38] In response to Board staff IRs, the Utility acknowledged the Board's suggestion about working with the other municipal electric utilities in Nova Scotia on performing a combined lead-lag study, which may be a cost-effective solution. The Utility noted that it intends to explore that possibility before its next GRA.

3.1.5.1 Findings

[39] The Board recognizes that the Utility requires a reasonable amount of working capital. However, the Board is concerned that a working capital allowance that is too high in rates could reduce the Utility's motivation to review its operations to continue to find efficiencies. Without a formal lead-lag study, the Board has concerns about the reasonableness of the amount of the working capital allowance request in this proceeding. Nevertheless, recognizing that the cost of such a study is often prohibitive for a small utility, the Board will allow the use of 10% of net cash expenses in this proceeding.

[40] Given that their working capital is already 36% of rate base, the Board accepts the Utility's decision to not include average inventory levels and customer deposits in working capital requirements.

[41] The Board understands the potential costs involved in a lead-lag study. However, the Board expects some assessment based on the Utility's information to be included in its next GRA. Alternatively, as noted in its other recent municipal electric utility decisions, the Board encourages the Nova Scotia municipal electric utilities to consider whether a collaborative lead-lag study may be a cost-effective alternative to assess the

utilities' requirements for working capital, based on information that is more closely related to their operations and jurisdiction.

3.1.6 Capital Structure and Rate of Return

[42] The Utility asked the Board to approve a rate of return on its rate base (or a weighted average return on capital) of 6.1% based on a capital structure of 60% debt and 40% equity. The Utility estimates that its cost of debt is 4.5% and requested a return on equity of 8.5%. The Utility said the deemed capital structure was consistent with the structure NS Power proposed in its recent GRA. The Utility also noted that this was found to be reasonable for small distribution utilities elsewhere in Canada, and recently for the Berwick Electric Utility.

[43] The rate of return requested by the Utility in this application is higher than what the Board approved for Berwick. For Berwick's Electric Utility, the Board approved a return on equity of 7.5% (1% lower than being requested by Antigonish), and 3% for its cost of debt (1.5% lower than what is being requested by Antigonish).

[44] The Utility noted that it did not retain a specialist on its cost of equity as it felt the cost of such an assessment would exceed the incremental increase to revenue requirement. The Utility did however provide its rationale for an 8.5% return on equity as follows:

> (a) That the appropriate benchmark for TOAEU's rate of return on equity is that approved by this Board for NSPI, because TOAEU faces many, although not all of the same risks faced by NSPI. BDR proposes that an appropriate risk-based differential between TOAEU and NSPI would be 100 basis points (1.0%); and
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> (b) That the rate of return on low risk/risk free capital has increased by 40 to 60 basis points since the time when the applications of TOMBEU and RELC were being prepared and then heard by this Board, and therefore a fair rate of return on equity should also be considered to have increased by approximately the same amount; and based on (a) and (b);

> (c) If the rate of 9.0% approved by the Board for NSPI is adjusted downward by 1.0% as an equity differential and upward by 0.5% reflecting increase in the long-term bond yields, this would result in a rate of return on equity for TOAEU of 8.5%.
>
> [Exhibit A-1, p. 9]

[45] The Utility noted differences between it and NS Power with regards to not having the risks of capital markets or the operations of an electricity generator. The Utility provided some additional justification for basing its requested return on equity, with a one percent adjustment, on what was approved for NS Power. The Utility cited general economic risks, customer base, procurement, and the same regulatory regime.

[46] Regarding general economic risk, the Utility suggested that, like NS Power, it operates in the same Nova Scotia economy and that both serve a base of domestic, business and institutional customers in that environment.

[47] For customer base risk, the Utility noted that 60% of its revenues are from non-domestic loads and that it is dependent on the ability of those customers to pay their bills. In addition, the Utility noted that more than 12% of its revenue comes from a single major customer, which puts it at risk as this customer can make future choices about facilities, activities, fuel and technologies.

[48] The Utility explained its procurement risk as a risk associated with the cost of procuring supply, of which a large percentage comes from a non-regulated source in the test year. The Utility claims that although it makes use of approved flow-through mechanisms for a portion of purchased power, it does not have the same reduction of risk as NS Power does with the use of a Fuel Adjustment Mechanism.

[49] The Utility also suggested that the regulatory regime risk it faces is the same as NS Power, as both are regulated by the same Board which has the power to deny approval of capital projects and other programs from their revenue requirements.

[50] The Utility's estimated 4.5% cost of debt is based on the current rates available from the Municipal Finance Corporation (MFC). The Utility noted that it did not intend to add to its long-term debt if the test year revenue requirement was approved by the Board, as the requirements for capital in the test year are minimal.

[51] During the hearing, the Utility was questioned on its current debt rate. The Utility noted that the rate of 4.5% was from MFC, approximately one year ago, when it was looking into the Grid Modernization Project.

[52] The Board also noted that the Utility's requested return on equity is a full percentage higher than the return recently approved for other municipal electric utilities in Nova Scotia. In response, the Utility cited recent interest rate and bond yield increases in Canada, as a reason for the higher amount. Considering return on equity typically adds a risk premium over the rate for debt, the Utility considers the requested 8.5% to be reasonable and consistent with what the Board recently approved for other municipal electric utilities, taking into account the changes in interest rates and bond yields.

[53] The Utility's proposed 8.5% 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, including NS Power, and rates achieved in other parts of Canada.

3.1.6.1 Findings

[54] 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.

[55] 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)]

[56] In the present case, the evidence provided to the Board assumed a cost of debt of 4.5% for new debt that the Utility would have available, based on interest rates available from MFC at the time of the Utility's capital expenditure application for the Grid Modernization Project.

[57] When approving the Berwick Electric Commission's cost of debt, the Board noted that the utility was not proposing to take out any new debt during the test year, and instead of approving the requested rate of 5%, the Board found that a cost of debt for that utility of 3% more accurately reflected its liabilities that would come due during the test year. Similarly, the Antigonish utility is not proposing any new debt during the test year and currently has no long-term debt on its books. The Board understands this will change shortly after the test year, as work gets completed on the Grid Modernization Project.

[58] In this matter, the Board finds that the current debt is low. There is no projected borrowing in the test year. A 4.5% cost of debt appears excessive in these circumstances. Additionally, 3% is the cost of debt the Board approved earlier (2023) for

the two other municipal electric utilities. The Board finds that the evidence in this proceeding does not warrant different treatment for Antigonish.

[59] 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 the Utility's cost of capital. Instead, the requested return on equity was benchmarked against other Nova Scotia electric utilities, primarily NS Power.

[60] The Utility is considerably smaller than NS Power. 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. Nevertheless, the fact remains that the evidence provided in this proceeding does not provide the Board with the information needed to satisfactorily assess a fair return.

[61] This is the same situation that was before the Board when it considered the recent general rate applications by the Berwick Electric Commission [2023 NSUARB 207], the Riverport Electric Light Commission [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. In the case of all three municipal electric utilities, the Board approved a return on equity of 7.5%.

[62] The Utility's evidence did not convince the Board that a return on equity of 8.5% is appropriate. The Board does not agree with the Utility's assertion that having one large customer increases its risk profile. This is a stable customer. As well the evidence indicates that while there may have been a short-term increase in interest rates, the long-term trend shows declining rates. Further, the Board does not agree with all of the

assumptions made by the Utility regarding its risk profile when compared to that of NS Power. The two most significant differences are that the Utility has no generation assets and does not require full access to capital markets. The Board sees these as major differences between the Utility and NS Power's risk profiles. The Utility did not provide enough evidence to persuade the Board otherwise.

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

3.2 Cost of Service

[64] BDR prepared the Rate Study for this application. The Utility has not had a GRA since the 1980s. BDR was, therefore, unable to say what cost of service items may have changed since its last rate application. As such, BDR used essentially the same cost of service methodology used in the BEC rate study filed and approved by the Board in 2023.

[65] Ms. Whited considered the cost allocation methods in her evidence. Overall, she found the methods to be sound. She noted some similarities to the methodology used for other recent municipal electric utilities' applications. However, she had concerns that she felt warranted future attention. The concerns are discussed below in the sections most appropriate for the concern in question.

3.2.1 Classification of Distribution System Costs

[66] Ms. Whited questioned the Utility's classification of distribution system costs upstream of the service drop. She noted the use of the minimum system method, which she said inappropriately classifies a portion of distribution system costs as customer related. Ms. Whited acknowledged that the approach proposed by the Utility was not

uncommon for allocating distribution system costs in North America. She indicated it is becoming less popular in favour of the basic customer method. The minimum system method was used and accepted by the Board in its recent decisions on the general rate applications filed by Berwick, Riverport, and Mahone Bay, on behalf of their electric utilities.

[67] Ms. Whited explained how the minimum system method works, as follows:

> The minimum system method classifies costs by estimating the cost of building from scratch a hypothetical system employing the smallest size components typically installed, and then deeming those costs to be customer related.
>
> [Exhibit A-5, p. 16]

[68] In her evidence, Ms. Whited explained the concerns she has with only using the minimum system method as follows:

> The minimum system method calculates the minimum size for each distribution plant type (e.g., poles and fixtures, conductors, transformers), and then classifies these costs as customer-related, while the remaining costs for each plant type are classified as demand related. This approach is at odds with the definition of customer-related costs found in the widely-cited text, *Principles of Public Utility Rates* by Professor James Bonbright. Professor Bonbright defines customer costs as the "operating and capital costs found to vary with number of customers regardless, or almost regardless, of power consumption." The costs associated with portions of the primary and secondary distribution system are primarily driven by the need to serve demand on the system, and thus it is not appropriate to classify these costs as customer-related.
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> [Exhibit A-5, pp. 16-17]

[69] While Ms. Whited agreed that methodological consistency was important, she did not consider the Board's earlier decisions for other utilities' methodology to be an endorsement of one method over another and encouraged the Board to direct the Utility to file rate studies under both methodologies in future rate applications.

[70] In response to Ms. Whited's issues surrounding the minimum system methodology and her suggestion for including both methodologies in its next rate application, Ms. Zarnett noted that the amount of work required to include the basic customer method would not be extensive. Ms. Barkhouse said the Utility is open to

providing both in future filings, provided there are the financial resources available, as they are not able to do the work in-house, and would require consultants.

[71] The Utility's closing argument, filed on April 11, 2024, made the argument that many methodologies could be used, though, other than the minimum system method "none of these methodologies are currently approved within the electric regulatory context of Nova Scotia." The Utility further argued that the Utility relies on the same methodology as approved for other municipal electric utilities in the province, and that filing a separate "non-approved" methodology would place additional burden on the Town and Utility.

3.2.1.1 Findings

[72] The approach used by the Utility to allocate distribution system costs has been commonly used by electric utilities in Nova Scotia, including NS Power. The Board finds 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 Ms. Whited (and by Synapse in the recent Berwick, Riverport, and Mahone Bay rate applications). However, the Board continues to hold the view that it expressed in an earlier decision:

> [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.
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> [*Mahone Bay (Town) (Re),* 2023 NSUARB 66]

[73] The Board agrees with Ms. Whited, that it may be of benefit to provide rate studies based on both methodologies as part of the Utility's next rate application. This would provide additional information for the Board to consider when approving rates and

related cost of service methodologies. In addition, at the hearing, the Utility's consultants noted that it would not be much additional work to include this approach in a future filing.

[74] The Board notes that there is not an "approved" cost of service methodology for municipal electric utilities, as there is with water utilities in Nova Scotia. In the past, the Board has approved NS Power's GRA and other rate studies on the merit of the evidence, rather than approving a methodology. The Board also notes that providing additional evidence for the Board to consider does not mean it would choose that methodology over the status quo, or that the same information wouldn't be requested from the other municipal utilities if it is proven useful. However, the Board agrees that providing additional information will aid the Board, so the Board sees merit in providing both. As it would not place an onerous burden on the Utility, the Board directs that it provide both methodologies in its next GRA.

3.2.2 Demand Allocation Factors

[75] The Utility noted that its coincident peak (CP) and non-coincident peak (NCP) demand factors were used for the allocation of costs to allocate demand-related costs to customer classes. The coincident peak factor was used for purchased power and substation-related costs, while the non-coincident peak was used to allocate other demand-related costs of assets downstream, including transformers, distribution lines and poles.

[76] The preferred approach taken by the Utility to determine coincident and non-coincident peaks is to:

> …use load data (kW) collected for each hour of the year from individual TOAEU customer meters for the entire customer population, or alternatively on a sample basis. The hourly load data, or "load shape" would then be used to identify the CP and NCP for each customer class. In TOAEU's situation where hourly load data is only available for the Large

> General customer class, alternative methods have been used to derive load shapes for each customer class which is described in the following paragraphs.
>
> [Exhibit A-1, p. 23]

[77] Since the Utility does not have all the information for the preferred approach, it noted that it uses a three-step method to estimate both the CP and NCP as follows:

> A. Determine the 2019 NCP for each customer class - The year 2019 has been used because there is publicly availability data collected in that year for Domestic and small general service consumers in Nova Scotia. This data has been used to estimate the 2019 load shapes for TOAEU Domestic and General Service < 3 kW customer classes. The 2019 NCP for the Large General, Unmetered and General Service > 3 kW classes have been determined using TOAEU data and estimates as described below. The resulting NCP demand factors (%) calculated with this data and estimates for 2019, has been applied for the 2024/25 Test year for the purposes of the cost allocation study.
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> B. Diversity Adjustment – Calculated as the CP divided by the NCP, the diversity adjustment has either been estimated or calculated as described below for each customer class.
>
> C. Determine the 2019 CP – the CP is determined by multiplying the NCP from step A and diversity adjustment from step B. The exception is the General Service > 3 kW customer class which is calculated as the residual difference from the 2019 coincident system peak, less the calculated CP for each of the other customer classes. As above for the NCP, the CP demand factors calculated using the 2019 CP's have been applied to the 2024/25 Test year for the purposes of the cost allocation study.
>
> [Exhibit A-1, p. 23]

[78] Ms. Whited noted that the Utility does not have accurate CP or NCP estimates, specifically for the General Service <3kW class, which could result in inaccurate estimates of the customer class costs. She did note that the lack of data should be addressed by the installation of advanced (smart) meters, which is part of the Grid Modernization Project, recently approved by the Board.

3.2.2.1 Findings

[79] In these circumstances, the Board finds that the Utility's peak estimates for the test year are reasonable. However, the Board understands the concern raised by Ms. Whited about the uncertainty associated with the General Service peaks. The Board notes that as part of the Board-approved Grid Modernization Project, the Utility intends to

convert its customers to smart meters in the final phase of that project. When this phase is completed, it is expected to improve the data available to determine class peaks.

3.2.3 Allocation of Purchased Power Costs

[80] The Utility noted that its purchased power costs have energy-related and demand-related components. The amount of purchased power allocated to demand and energy has been calculated by applying the power suppliers' rates to the forecast purchases for the test year. It allocates the energy-related costs to its customer classes based on their annual energy usage.

3.2.3.1 Findings

[81] If purchased power costs are allocated based on annual usage and demand, there could be seasonal variations in the energy used by the various customer classes. This variation could result in cost differences throughout the year that would be different than those determined on an overall annual basis. In the BEC rate application, Board Counsel consultant 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.

[82] 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 small utility. It could increase the costs and time associated with developing a rate application for little or no benefit. The Board accepts that the allocations for purchased power costs are appropriate based on the available evidence in this matter. However, after the installation of AMI metering technology, the Utility should periodically assess whether a

more robust approach would result in a more reasonable allocation of costs between rate classes.

3.3 Rates and Charges

3.3.1 Revenue-to-Cost Ratios

[83] Exhibit A-1(ix) (Exhibits 5 and 6) set out calculations showing a revenue shortfall in 2024/25 of $918,515 under existing rates. The exhibit further shows the need for an overall average rate increase of 6.29% to satisfy the proposed revenue requirement. Under existing rates, the Utility's cost of service analysis shows that all rate classes are under-recovering revenue, except for the combined general service >3kWh and large general service classes, which fall within the 95% to 105% revenue-to-cost range the Board considers to be reasonable. Street lighting is recovering less than a quarter of the costs of providing that service.

[84] To address the shortfall in revenue under current rates, the Utility proposed the following:

a. Unmetered lighting rates would increase by 125% of the system average increase but would still only fall at a revenue-to-cost ratio of approximately 26%.
b. General service class <3kW rates would increase by 7.2% and have a revenue-to-cost ratio of approximately 74.67%.
c. General service >3kW and Large general service would increase by a combined 5.7% and put the revenue-to-cost ratio to 103.84%.
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.

[85] In response to Board Staff IR-21, the Utility referred to the Board's decision in BEC's recent general rate application. The Board's decision in that case was not issued when the Antigonish Utility was preparing its rate study. The Board directed BEC to increase street lighting rates by 1.75 times the average increase. The Utility noted that had that information been available, it would have used 1.75 in this rate study. The Utility further commented that such an adjustment could be made as part of a compliance filing in this proceeding. In the same IR response, the Utility noted that the increase in streetlighting rates for BEC was 39.4%.

[86] Ms. Whited suggested that the Utility increase the rates for street lighting from 1.25 times the system average to 1.75 times. The Board observes that this Utility is requesting relatively smaller increases than was the case for BEC and Mahone Bay. This means 1.25, 1.50 or 1.75 times the average increase keeps the change for street lighting well below what was seen in Berwick. A 1.75 times increase would only increase the street lighting rates by approximately 11% compared to an increase of 39.4% in Berwick and approximately 38% in Mahone Bay.

[87] The Board notes that in the BEC GRA, the rate for an 88-Watt LED increased by almost $4 per month to $15.8102 per month while in the Mahone Bay GRA the 83-Watt LED rate increased by about $8 to $23.64. Both Utilities have since had flow-through rate applications which further increased the street lighting rates. The Utility's current rate for an 88-watt LED is $12.58 per month, an increase of 1.25 times the average results in a rate of $13.24 per month. If the rate is increased by 1.75 times the average, it would be about $13.50 per month.

[88] Turning to the proposed increases in other rate classes, Ms. Whited suggested that the Board approve the same 7.2% increase for the general service rate

class <3kW. She recognized that the rate class would be well under the Board accepted 95% to 105% ratio of revenue-to-cost but suggested the Utility submit a revised rate class or consolidate it with the general service >3kW class within three years of installing AMI.

[89] In its rebuttal evidence, the Utility agreed with Ms. Whited's recommendation regarding reviewing the general service rates, to develop a revised or consolidated rate class or an explanation as to why the existing rate class should remain in place. However, the Utility suggested that any change or explanation should be included in the first GRA following the installation of AMI. The Utility would like to review the available information and consider what is best for the ratepayers.

3.3.1.1 Findings

[90] The Board has concerns about the substantial under-recovery of costs through the street lighting rates. The Board recognizes that the Utility shares that concern, as evidenced by its initial proposal for a greater increase in the proposed rates for this rate class. The Utility now agrees with Ms. Whited that the amount should be further increased to 1.75 times the system average increase.

[91] 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 the Mahone Bay and Berwick's GRAs. While rate shock is not a major concern when considering streetlighting, the Board accepts the evidence presented by the Utility and Ms. Whited and directs that the street lighting class increase be 1.75 times the system average.

[92] The Board agrees that at this time, the general service <3kW should be increased by 7.2%, even though the revenue-to-cost ratio would place this class below the 95% threshold.

[93] The Board suggests that the Utility file a GRA within three years, at most, after completing the AMI installation. As part of that process, the Utility should include a plan for adjusting the general service rate classes or provide detailed reasons why no change should be made. Any recommended action, including the status quo, should be backed up with empirical evidence.

[94] Based on the rate study filed in this proceeding, the Board believes that with this decision all rate classes will be within the Board's 95% to 105% revenue-to-cost range (except for the street lighting class and general service <3kW 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 street lighting class and general service <3kW), that rate class should be increased to 95% and the revenue responsibility of the remaining rate classes (excluding the street lighting, small general and general service classes) should be reduced proportionately so long as they are above a 95% revenue-to-cost ratio.

[95] Overall, the Board considers this approach to be similar to what BEC and Mahone Bary proposed, except for the larger increase for the street lighting class and the revenue-to-cost ratio for general service <3kW.

3.3.2 Domestic Customer Service Charges

[96] In its decisions on the Riverport Electric Light Commission 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 applying the same percentage increase to the customer service and energy charges. This resulted in smaller customer charge increases than proposed in those cases.

[97] In the BEC rate application, BEC acknowledged the above precedent but noted that its existing domestic service charge was $20.19 per month. Using the method directed by the Board in the Riverport Electric Light Commission and Mahone Bay cases would have resulted in a customer service charge of only $7.73. In that circumstance, BEC proposed to keep its service charge at its current rate, and the Board approved that proposal.

[98] In this application, the customer service charge issue is similar to BEC's. The Utility's current charge is $16.95, while the cost of service allocated to this charge indicates the charge should be set at $12.74. Like in the BEC matter, the Utility is proposing to keep its service charge at the current rate and have the increased revenue requirement captured in the energy charge.

[99] In her evidence, Ms. Whited recommended that the Board reduce the service charge for the Domestic rate class to $12.74, which was supported by the Utility's analysis. She noted that the proposed service charge is not justified on a cost-causation basis and that it would move rates further from the unit costs in the rate study.

[100] The Utility noted that reducing the service charge and increasing the volumetric (energy) rate would exacerbate the bill increases for Domestic customers with higher consumption, particularly in winter months.

[101] Ms. Whited did not agree with the Utility's position on this issue and noted that for the majority of customers, having a lower service charge and higher consumption

charge would lead to lower overall bills, based on 2023 average monthly usage, as most customers fall below average total usage.

[102] In the Utility's rebuttal evidence, it indicated it did not agree with the recommendation to lower the charge to $12.74 and noted that holding the charge at the current level is consistent with the approach approved by the Board in the recent BEC GRA.

[103] At the hearing, Board Counsel asked the Utility's witnesses about this issue and the appropriateness of the current $16.95 charge. The Utility indicated that the current charge was, in part, at the level it was due to the way the flow-through mechanism works, which applies the same percentage increase to the service charge and consumption fee. Before the most recent flow-through approval, the service charge was $16.09. It was even lower in past years. The service charge has not been set based on allocated costs since the Utility's last GRA in the 1980s.

[104] During the hearing, Board Counsel asked the Utility whether it took issue with Ms. Whited's analysis about the number of customers that would benefit from a lower service charge:

> Q. So my question for the Panel is whether you take any issue with that analysis as presented here in Ms. Whited's testimony.
>
> A. … (Zarnett) ... I just would like to point out that there's a difference between a customer and a bill impacted. So customers would tend to have lower bills overall in the summer months where there could be a reduction, but for many customers this would be offset entirely by increases in the winter bills, which are already the highest of the year and therefore impose the most burden on the customer's monthly budget. So that's just from the standpoint of the bill impact, and it's a different matter entirely to aggregate the bills of customers through the year and determine how an individual customer on an annual basis will be impacted.
>
> …

> (inaudible - talkover) over the year of the lower bills in the summer months, which would be impacted as Ms. Whited describes, but their winter bills would then be increased by the same change.
>
> [Transcript, pp. 22-23]

[105] Board Counsel then asked the Utility if it agreed with Ms. Whited's evidence that lowering the service charge to $12.74 (and increasing the energy charge) would improve intra-class equity and that under the Utility's proposal, lower-usage customers would be subsidizing higher-usage customers. Board Counsel also asked whether a lower fixed charge and higher volumetric rate could provide a more efficient price signal to encourage energy efficiency:

> A. (Zarnett) That ... that's true in the sense that 12.74 is the cost-based charge and it would result in subsidy as between higher- and lower-use customers. However, I don't support the conclusion that the rate design should be based on that at this time.
>
> Q. (Mr. Mahody): And on page 10 of her evidence Ms. Whited indicates:
>
>> Finally, lower-fixed charged and higher volumetric rate provides a more efficient price signal that encourages customers to use electricity efficiently and invests in distributed energy resources to reduce their energy consumption, such as energy efficiency and distributed generation.
>
> Does the Panel take any issue with that factor that Ms. Whited has cited in support of her position?
>
> A. (Zarnett) That's true… to whatever degree customers are, in fact, sensitive to price on this basis.
>
> The price ... elasticity of demand is what I was talking about.
>
> [Transcript, pp. 24-25]

[106] In its closing arguments, the Utility noted that it supported Ms. Zarnett's comments on this issue when replying to the Board Panel. In this interaction, Ms. Zarnett stated:

> When we came to Berwick, as in Antigonish's case, the level of cost-based charge would necessitate a decrease in that charge from the current level. So we're in a time of increasing total cost, but one component would be reduced and the other increased more to compensate.
>
> So that's the concern. It will cause a differential impact in terms of the bills of different customers at a time of significantly increasing costs over the last two years. We don't know

> what the cost increases will be next year. So I have concerns as a rate designer of, even though a relative adjustment is absolutely reasonable ... to have an absolute adjustment in a component of the rate.
>
> The other concern that I have is for consistency with the future. This utility is expecting to spend significant amounts of capital. A significant amount will involve new metering and new components of the distribution system, which the metres (sic) will absolutely be classified as customer-related costs. They will be new, they will be expensive, and as well, if the cost allocation methodology remains as currently the minimum system basis there will be significant increases to the customer elements as well. So I'm concerned about seeing a significant reduction in the fixed charge on this application only to be put up again a couple of years from now.
>
> [Transcript, pp 51-52]

3.3.2.1 Findings

[107] The Board accepts that Ms. Whited's recommendations are based on sound utility rate-making principles. The Board believes that the customer service charge should recover customer-related costs. The Board finds that based on cost of service principles, the customer service charge should be $12.74. The Board directs the Utility to make this adjustment in a compliance filing.

[108] In addition, the Board recognizes the impact of the approved flow-through mechanisms on the customer base charges. The Board urges the Utility to consider requesting that any future flow-through mechanism increases flow directly to the energy charge, rather than to all fees and charges, some of which should not be impacted by an increased cost of purchased power.

3.3.3 Time-of-Use Rates

[109] The Utility was not able to provide support for the cost basis of its optional domestic Time-of-Use Rates. Currently, only four customers use the optional Time-of-Use Rates. This has not changed since 2017 and is projected to remain the same for the test year. The per-customer actual usage has remained relatively flat from 2017 to 2022 (a decrease of 0.3%).

[110] The Optional Domestic Time-of-Use Rate is structured as originally approved by the Board. There is a monthly base charge and energy charges for peak, shoulder, and off-peak times. The rating periods cover the time of day, day of the week, and seasonality, reflecting a winter peak load for the Utility.

[111] The Utility observed that the shoulder rate for its domestic Time-of-Use Rates should be set at the regular domestic energy rate. The peak charge doubles the shoulder rate. The off-peak rate is designed to recover the variable cost of wholesale energy, adjusted for losses at 4%.

[112] The Utility is not proposing to invest resources to review the appropriateness of the rate structure and methodology at this time and requested the Board approve new rates set out as above, which used the same methodology as when the rate class was originally approved by the Board. In addition to the usage charges, the Utility proposes that the base rate be adjusted by the same percentage that is applied to the fixed monthly charge for Domestic non-time varying rates.

[113] The Utility 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 4.0%, and therefore the rates in all rating periods will contribute to the recovery of the Utility's costs to deliver supply to the customers.

[114] Ms. Whited recommended that the Utility propose at least one new advanced rate design, and modifications or closure of the current Time-of-Day rate, within three years of the planned installation of AMI. In her evidence, she noted:

> The advanced meters that TOAEU plans to install will permit the utility to implement much more sophisticated rates, such as a rate for customers who adopt beneficial electrification technologies (such as electric vehicles or heat pumps), or a time-of-use rate that is open to all customers. In addition, the results from Nova Scotia Power's ongoing time-varying pricing pilot will provide useful information regarding which rate structures are likely to be

> most effective in promoting load shifting. Electrification and load shifting are vital to achieving both local and federal net zero emissions targets in a least-cost manner.
>
> [Exhibit A-5, p. 13]

[115] Ms. Whited did not bring forward any other concerns regarding the Time-of-Day rates or methodology being proposed by the Utility.

[116] In the Utility's rebuttal evidence, it noted that it did not agree with setting at least one new advanced rate design, or closure/modification of the current Time-of-Day rate within three years of installation of AMI. The Utility explained why it didn't agree with this recommendation but did agree to study the issue of advanced rate design following the installation of AMI and provide the findings to the Board. The Utility also noted that:

> TOA would caution that such a study could lead to the conclusion that no new advanced rates are required, as there may not be a time-based cost pattern that is significant enough or consistent enough to justify a change in rate structure. In advance of a study, it would be premature to commit to implementing any specific new rate design at this time.
>
> [Exhibit A-7, p. 2]

[117] Mr. Mahody canvassed the Utility further on this issue:

> Q. … the Utility again commits to studying the issue, and I'm wondering what would be the rationale for delaying the proposal of a new rate and the proposal to modify the time-of-day rate into well into the 2030s? What's the reason why that work couldn't be committed to occurring in the timeframe that Synapse has proposed?
>
> A. (Barkhouse): So the reason with the ... the reason why we do not want to commit to a timeframe at this point for any new rate design is we need to study it. It is new to the Utility. We are a non-generating utility. So by looking at a time-of-use rates ... because that's for ... like, demand shifting by trying to, you know, reward individuals for using electricity on off-peak times and having higher rates for on-peak times is just to understand how that would impact the Utility and our purchase of wholesale electricity.
>
> ...
>
> A. (Zarnett) There would be two aspects involved. One is that more data would be needed to achieve an understanding of the customer's load shapes. So that's from the metres that are proposed to be installed.
>
> The other thing that would need some study and would probably be changed in the next several years is the degree of time-relatedness of the costs as incurred by the Town of Antigonish Utility. Currently, they're not facing time-related rates in terms of their wind contract. The rates from Nova Scotia Power to municipals are not time-related, and therefore the question remains of whether there's a significant ... there is seasonal but not ... how to quantify whether there's a time, an hourly difference, in the incurrence of the costs of power.

So that would probably ... that would change if, for instance, Nova Scotia [Power] implemented a time-based rate at the municipal rate or if supply mix of the Utility were significantly changed, in which case that would have to also be studied.

Q. And Ms. Zarnett, studying that issue and studying the data that's received from the AMI metres that would be installed by the end of 2027, would you anticipate that both of those studies could be completed within a three-year time period and recommendations be based on that study material?

A. (Zarnett) I would say from my point of view that there should be at least, at the very least, a full year of data from the time of these metres. A full year is needed in order to do the analysis. A little more would be better in order to confirm that the data ... the year of data is consistent, is accurate, isn't gapped or missing or otherwise inaccurate.

So you know, perhaps - perhaps - 18 months would be good to collect the data and then there needs to be some period to do the analysis.

[Transcript, pp. 29-31]

3.3.3.1 Findings

[118] The Board approves the Utility's proposal for its optional Time-of-Day rates, subject to any adjustments required by its directives elsewhere in this decision, including the amendments to the domestic customer charge. The Board directs the Utility to further assess the cost basis and reasonableness of these rates beginning 18 months after the installation of AMI. When the study is complete the Utility is directed to share the findings with the Board. If the study determines that either a new advanced rate design, or closure/modification of the current Time-of-Day class is warranted, the Utility shall bring forward its proposal(s) at either the next GRA following the study or may apply for the changes to any existing rate class or creations of a new rate class outside of the GRA process.

3.3.4 General Service Declining Block Rate Structure

[119] The Utility currently has a declining block rate structure for its general service class. The Utility proposed to keep this rate structure in this application.

[120] Ms. Whited noted that the declining block rate structure is not supported by any analysis and may lead to wasteful consumption and intra-class inequities. Ms. Whited recommended that the Utility file a proposal to eliminate the rate structure in its next GRA application unless it can provide adequate support that the structure is cost reflective.

[121] Ms. Whited provided further explanation of why she believes the rate structure should be eliminated as follows:

> Q. **What concerns do you have regarding TOAEU's declining block rate structure?**
>
> A. I am concerned that the declining block rate structure has not been shown to be cost-based and may therefore be both inequitable and inefficient. TOAEU states that it "has no record of previous cost analysis supporting the general service rate design and has not undertaken any data collection or analysis of the cost basis of the rate for purposes of this application."
>
> Q. **In what ways are declining block rates inequitable?**
>
> A. Declining block rates price higher levels of consumption at a lower rate. If such rates do not accurately reflect the costs associated with serving additional load, they may lead to lower-usage customers subsidizing higher-usage customers.
>
> Q. **In what ways do declining block rates provide inefficient price signals?**
>
> A. Declining block rates reduce the marginal cost of electricity consumption faced by customers whose consumption is higher than the size of the first block. By lowering the cost that customers face for higher levels of electricity consumption, declining block rates can lead to wasteful usage by reducing incentives for conservation and energy efficiency. This could eventually result in higher generation, transmission, and distribution costs for all customers. For these reasons, many jurisdictions have moved away from declining block rates.
>
> [Exhibit A-5, pp. 10-11]

[122] In its rebuttal evidence, the Utility suggested that to be consistent with the Board's decisions in the recent GRAs for Riverport and Mahone Bay, the Utility should review whether the declining block rate can be justified from a cost perspective and provide that analysis in its next GRA process.

[123] During the hearing, Board Counsel asked the Utility if they would bring forward a proposal if the analysis suggested that approach, as opposed to just providing

the study as noted in the rebuttal evidence. Ms. Barkhouse confirmed that the Utility would bring forward the study and its findings with a proposed recommendation of how to move forward on the issue of declining block rate structure.

[124] During questioning, Ms. Zarnett provided information about how the current structure works, and why it wasn't an issue in this proceeding to determine if it should remain or not:

> It's not clearly understandable from the phrasing of Synapse's recommendation of ... that what's being referred to here is not a fixed ... an energy charge structure the way it is for the domestic charge. The rate that's being referred to here is the general service rates. Those rates have no fixed charge. It's a demand charge and energy blocks, and the way that it works is that the blocking assigns kilowatt hours between the blocks based ... not absolutely but based on the level of demand.
>
> So if the customer has, for instance, four kilowatts of demand there would be 400 kilowatt hours in the first block. If the customer's demand were 500 for five kilowatt hours there are 500 kilowatt hours. It is a demand and energy rate whose purpose is to give the same average bill per kilowatt or for kilowatt hour for customers of different sizes with the same load factor.
>
> If the rate were to change with virtually zero impact to all the customers in the class that could be done by taking ... smoothing out the blocks, or rather reassigning all kilowatt hours to the balance block and putting the differential between the energy block charges into the demand charge instead. That would give every customer who uses more than 100 kilowatt hours per kilowatt, the same bill as they get today.
>
> If the Board prefers that it can easily be done. The good thing about this structure, and the reason why historically utilities have used it, is that there's the occasional customer that has equipment that is used for a short period of time with very high demand. So they're customers with extremely low load factor and this structure will give that kind of customer a little bit of a break based on the assumption that, that demand would have a high probability of being mostly off. Not off-peak in the sense of being at night, but it would have diversity with other loads in the class.
>
> The other thing that I looked at to determine the cost basis was to compare the demand and energy split of the revenue versus the demand and energy split of the allocated costs. For the allocated costs, they're, depending on how you treat the customer element, about 32 and 36 percent. On the revenue side it's 29 percent.
>
> So on that basis an argument could be made to increase the demand charge a little at the expense of energy charges. However, this demand energy split is contingent on the power supply and the Nova Scotia Power rate as they exist today as the Utility is purchasing today, and if there was a change in the mix it would likely be in the direction of less demand and more energy.
>
> So on that basis my conclusion is that there's nothing seriously wrong with this rate and that the only reason to go to something entirely different would be based on data coming from the smart metres (sic).

[Transcript, pp. 26-28]

3.3.4.1 Findings

[125] The Board approves the Utility's request to maintain the general service class declining block rate structure at this time. The Board directs the Utility to perform a study on the appropriateness of such a rate structure and to provide a proposal on moving forward with a justified block structure or plan to remove the declining block structure, as part of its next GRA.

3.3.5 Streetlights and Yard Lights

[126] The Utility proposed changes to its streetlighting rate structure, which includes having a base charge and service charge per wattage per year for LED streetlights. Currently, the Utility only has rates for 55-watt and 88-watt LED lights. The new rate structure would allow the Utility to set rates for LED lights of any wattage. The Utility determined the current rates by setting the fixed charge of $48.88 plus $1.07272 per Watt. If applied to the two sizes of lights currently rated, it would provide the same total of $107.88 annually for 55 watts and $143.28 for 88 watts.

[127] Ms. Barkhouse provided further information at the hearing about why the Utility is proposing to use a fixed and variable component for LED streetlights:

> A. So in regards to the LED lights, we don't have a fixed watt usage that we have. It's not like all the lights are 55 or 50 or 65. The goal is usually to get ... there's two things, to have a fairly consistent lumen rating, and as technologies improve, you may keep that lumen rating at one number and then the wattage has gone down.
>
> And also, we're looking for best deals or ... with the manufacturers. So you may be able to get an LED at a 52 watt at a cheaper price than a 51 watt, and so we're ... the goal was to purchase lights at the most ... best value for our rate customers.
>
> So when we looked at doing an audit of where exactly we were with our LEDs there was a wide range of wattages to have everything listed as if you are a 51 or a 55 or a 62. The idea of the fixed versus the variable charge would be as if an opportunity came to get an LED light that wasn't specifically listed on our rates and schedules. We would be able to use an appropriate rate for the cost and to update it.

> Because as you are aware, on our rate schedule there is two ... there's only two LED rates available. I believe it's 55 and 88. I would have to confirm those.
>
> Q. (Mr. Fisher) Right, so by going to a fixed and variable charge you're able to handle any specific wattage.
>
> A. (Ms. Barkhouse) Yes, that is the goal. Would either to be ... to offer that so the customer is only paying for the wattage that is associated with the light or the other option that was considered before the application was ... would to be to have a range where if something was in the 60 range - so 60 to 69 - there would be one rate for that, the midpoint, which would have some customers paying over and some paying under. But that would just be another option to have more coverage with those rates.
>
> But the idea was to go to the fixed and variable rates to get that more precise amount to the customer.
>
> [Transcript, pp. 132-133]

[128] In Undertaking U-5, the Utility confirmed that the streetlighting rates include a Demand Side Management charge, which is embedded in the rates.

[129] The Panel was asked about the allocation of working capital to streetlights. Working capital is allocated based on net plant but may very well have different cost drivers and could be over-estimating the costs attributed to streetlights. Ms. Zarnett provided her thoughts as follows:

> A. (Zarnett)... I did a cost allocation study based on methodology that I thought appropriate. I recommended that working capital should be broken down in terms of its allocation in accordance with how much came ... because this is the net cash expenses, how much came from costs of power, how much came from OM and A.
>
> That would be very good methodology, but since I've been out there in the world, I haven't seen that that's what others do. So we adopted a methodology that has been used in jurisdictions where I've worked and followed the methodology previously approved, but if this board wanted to see that alternative I would like it ... I would be extremely glad to have that happen and it's quite possible that the street lighting allocations need to be more deeply examined for a variety of reasons.
>
> Q. Would one of those reasons also relate to some of the billing factors there where I'm ... and I guess when you look at the number of accounts or the number ... there's a difference between number of accounts, number of customers, of course. And so is street ... with streetlights you may have one big customer, and it may not take as much work to do ... deal with 781 streetlights as it does to deal with 781 clients.
>
> A. (Zarnett) That's an interesting point. When I've discussed this with utilities and when I worked for a utility we found that an adjustment should be made versus one-to-one domestic bills and so on but that there were considerable costs associated with a back-office work of maintaining the inventory of lights, how many are there, who has them, and so on and that that's ... whereas for a domestic customer you don't have to do anything like that. You read the metre and you send out the bill. So there are different kinds of costs.

> They're worth reviewing. I think the part that ... the parts of a revenue requirement that layer onto the invested assets ... that's really where we should be looking.
>
> [Transcript, pp. 135-136

3.3.5.1 Findings

[130] The Board accepts the proposed new rate structures, subject to the change as noted above, increasing the streetlighting rates to 1.75 times the system average increase and including a fixed portion and variable portion to LED rates. This will allow the Utility to effectively price any watt LED light that gets added to the system. The Board agrees that having the flexibility to add a different watt LED is beneficial to the Utility and its customers.

[131] The Board encourages the Utility to take a closer look at allocations to streetlighting, including the allocation of working capital. The Utility is particularly encouraged to look at other ways certain costs can be allocated to better represent cost causation, with regards to streetlighting.

3.3.6 Schedule of Rules and Regulations - Pole Attachment Charge

[132] The only change in the Schedule of Rules and Regulations the Utility requested was to increase the rate it charges to telecommunications carriers to attach their equipment to its poles. The Utility currently charges $9.60 per pole per year. The Utility proposes to increase the charge to $22, an increase of $12.40 or nearly 129%.

[133] For years, the Utility maintained a pole attachment charge of $9.60, which was less than the rate charged by Berwick and NS Power before their last GRAs. The Utility explained that it aligned its proposal for the fee increase with the pole attachment fee negotiated in the settlement agreement 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 Berwick, Riverport Electric Light Commission, and Mahone Bay in their recent GRAs.

[134] The Utility indicated that it has approximately 500 pole attachments on its system, all for the same customer. For calculating the revenue requirement from rates, the proposed pole attachment charge is assumed to be in effect throughout the test year.

[135] During an exchange at the hearing, the Utility confirmed that it had not been collecting the approved pole attachment fee. In that exchange, Ms. Barkhouse noted:

> A. … So when I went back to look in the history of that, that got lost between the changeover between my pre- ... the person that I replaced and the person that they replaced. So this is going back a little bit.
>
> So that ... those invoices were not sent out and then right around the time I started, maybe a year or two in, we were receiving payments from Eastlink that were approximately what those ... the pole attachment fees should be, and that was allocated to the electric utility as the pole attachment revenue and everyone thought that was great until we started doing some research as part of this GRA and realised that, that was for an easement lease with the Town and not with the Utility.
>
> So I am in process of getting that updated to start billing Eastlink those poles' attachment fees.
>
> [Transcript, p. 161]

3.3.6.1 Findings

[136] The Board observes there were no interventions or challenges to the Utility's proposed pole attachment charge. The current charge has been in effect for decades, and the evidence indicates that the Utility has not been billing the only customer using the Utility's poles, outside of the Utility itself.

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

[138] The Board approves the pole attachment charge of $22/pole/year, and the related amendment to Schedule B – Schedule of Rules and Regulations (Regulation 44). The Board has some concerns that the Utility has not been collecting the fee for some time but understands that the Utility is committed to start billing the customer for its pole attachments. The Board suggests this should happen as soon as possible, as the revenue generated from the pole attachments is included in projected revenue, whether the Utility is receiving it or not.

[139] The Utility does not appear to have reviewed the fees in the Schedule of Rules and Regulations for some time. The Utility should review the appropriateness of these fees in its next GRA.

3.3.7 Flow-through Applications

[140] The Utility's current tariffs include mechanisms that allow it to update its rates in an expedited fashion to recover increased costs due to NS Power Municipal tariff 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. The Utility agreed that with the complex issues and the changing landscape of purchasing power, it would be appropriate to review the flow-through mechanism.

[141] There was a discussion with the panel where it was noted that the current flow-through mechanism is applied to both the base and usage charges. As such, it was the flow-through mechanism that pushed the base charge for domestic customers to the current $16.95, and before that to $16.09. Both of these amounts are above the $12.74 calculated in the rate study. The flow-through mechanism as is, may continue to push the base charge higher than calculated under a cost of service methodology.

[142] In regard to the flow-through mechanism's impact on the base charge, Ms. Zarnett said:

> I would say that it's time to review the formula anyway, and to make a decision as to whether the priority is to keep ... to share out the flow-through or to put those costs pretty much where they belong, which is in the energy or in a combination of demand and energy but **not in a customer based fixed charge.** [Emphasis added]
>
> [Transcript, p. 122]

[143] The Board encourages the Utility 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.

4.0 SUMMARY

[144] The Board approves the proposed changes to the Utility's Schedule of Rates for Electric Supply and Service and its Schedule of Rules and Regulations Governing the Supply of Electric Services, subject to the following:

- The cost of debt used to determine the revenue requirement will be 3%.
- The cost of equity used to determine the revenue requirement will be 7.5%.
- The unmetered street lighting rates will be increased by 175% of the system average increase.
- Distribution line losses are set at 4%.
- The depreciation expense must be corrected in accordance with the response to Undertaking U-4.
- The domestic Customer Service Charge is set at $12.74, and the Time-of-Use Base Charge is to be amended accordingly.

[145] The Utility is directed to file a compliance filing, no later than May 20, 2024, to address the changes to its application required by this decision. The compliance filing must include updated versions, in Excel format, of its application exhibits (Exhibits 1-1 to 6) in Exhibit A-1. The compliance filing must also include clean and redlined versions of the Utility's new tariffs and regulations.

[146] The Utility is further directed as follows:

- In its next general rate application, the Utility must:
  - provide a rate study using the basic customer method along with the current minimum system method;
  - complete a study on the appropriateness of the declining block rate structure and to provide a proposal on moving forward with a justified block structure or plan to remove the declining block structure;
- File a rate study within three years of the installation of AMI. In that general rate application, the Utility 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-Day Rates, and provide analysis on advance rate design and if a new rate class should be created;
  - Assess if the General Service <3kW should be merged with general Service >3kW, or if a new rate class cut-off should be implemented.
- The Utility must also:
  - start billing the Pole Attachment charge.

[147] Following a compliance filing, an Order will be issued accordingly.

DATED at Halifax, Nova Scotia, this 9th of May 2024.

Richard J. Melanson

Steven M. Murphy

Bruce H. Fisher