DECISION **2025 NSEB 9**
M12179

NOVA SCOTIA ENERGY BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF AN APPLICATION by **THE TOWN OF LUNENBURG, 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:	Stephen T. McGrath, K.C., Chair Jennifer L. Nicholson, CPA, CA, Member Bruce H. Fisher, MPA, CPA, Member
APPLICANT:	**TOWN OF LUNENBURG ELECTRIC UTILITY** James MacDuff, Counsel
BOARD COUNSEL:	William L. Mahody, K.C.
HEARING DATE(S):	July 22, 2025
UNDERTAKINGS:	July 28, 2025
DECISION DATE:	**August 28, 2025**
DECISION:	**The application is approved, subject to adjustments as outlined in this decision and a compliance filing.**

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1.0 INTRODUCTION

[1] On March 31, 2025, the Town of Lunenburg, on behalf of its electric utility, applied to the Nova Scotia Utility and Review Board (NSUARB) to change its rates for electric supply and services, and its charges and fees for pole attachments, permits and inspections. On April 1, 2025, on proclamation of the *Energy and Regulatory Boards Act*, S.N.S. 2024, c. 2, Sch. A, the NSUARB was succeeded by the Nova Scotia Energy Board for all applications related to electric utilities.

[2] The utility stated in its application that it has been operating at a deficit and requested an overall average rate increase of 16.7% for 2025/26.

[3] On July 22, 2025, the Board held a public hearing in the Town of Lunenburg Council Chambers. The hearing was also live streamed. Lisa Dagley, the Town's Finance Director, testified on behalf of the utility. The utility's consultants, Paula Zarnett and Trent Winstone, both of BDR North America Inc., appeared virtually. Board Counsel consultant, Ben Havumaki, Synapse Energy Economics, Inc., also testified virtually.

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

[5] The Board approves the utility's application subject to the adjustments and directives in this decision. These adjustments are to be confirmed and approved in a compliance filing.

2.0 BACKGROUND

[6] The Town of Lunenburg's electric utility serves the town and surrounding communities, including Garden Lots, Blue Rocks, First Peninsula, Stonehurst, Mason's Beach and Lilydale. It has approximately 2,320 metered customers and 661 unmetered lighting and other small services customers.

[7] The NSUARB approved the utility's current rates in late 2013 (2013 NSUARB 248). Since then, rates have risen because of flow-through applications, which passed along changes in the cost of purchased power from Nova Scotia Power Incorporated (NS Power). The most recent flow-through application was approved by the NSUARB under Matter M11482 and came into effect on January 1, 2024.

[8] The utility said it was able to continue without a general rate application since 2013 because of the flow-through mechanism and a modest program of capital additions. It said that in four of the most recent years for which audited financial statements are available (years ended March 2020, 2021, 2022 and 2023) revenues have been adequate to cover current operating expenses, scheduled repayments of principal on a long-term loan, and some transfers to reserves. However, for the year ending March 31, 2024, an operating loss was experienced, without accounting for loan repayments, and no transfer to reserves was made. When it filed its application, the utility projected an operating loss of $384,985 in the year ending March 2025.

[9] The utility said that, in addition to budgeted escalations in administrative, general and customer service costs, increases for the Test Year (2025/26) are being driven by a planned five-year program of capital spending. This program totals approximately $14 million for substation and distribution assets, which will increase operating and maintenance costs, amortization and interest on long-term borrowing (as

the spending will be funded primarily through long-term debt). Of this five-year program, approximately $2.6 million in capital spending is planned for the Test Year, which will be in addition to the utility's budget of $670,000 for routine capital work. The utility submitted the projected capital work is needed urgently to continue providing safe and reliable service to its customers, at the standard expected of a modern distribution utility.

[10] Given the foregoing, the utility said it cannot continue to provide service at its currently approved rates without severe detriment to its financial integrity. The utility seeks the approval of a revenue requirement of $8,895,622 for 2025/26, which would require an overall average rate increase of 16.7%. However, the utility proposes to cap the rate increases for its most impacted rate classes to 15%, with the difference and interest to accrue in a regulatory deferral account for recovery from those rate classes in the future.

3.0 DISCUSSION AND ANALYSIS

3.1 Load Forecast

[11] The utility adopted a load forecast methodology similar to what was used by other municipal electric utilities in their recent general rate applications. It used weather normalized consumption over a 10-year period, heating degree day data (HDD), observed trends, and customer knowledge to varying degrees to estimate the load for each rate class. The Domestic, Time of Day and Small General forecasts used trends in average kWh, while the General and Large General class loads "relied primarily on observed historic trends and knowledge of its customer base".

[12] The utility provided additional details about its load forecast in response to Undertaking U-2 [Exhibit L-9(i)]. Its estimates are summarized in its “Exhibit 2 Load Forecast” tab in Exhibit L-1(iv):

							Exhibit 2
TOWN OF LUNENBURG ELECTRIC UTILITY							
Load Forecast							
Connections	**Actual**	**Actual**		**Projected**		**Test Year**	
	2022/23	**2023/24**	% Growth	**2024/25**	% Growth	**2025/26**	% Growth
Domestic Standard	1,818	1,860	2.3%	1,878	1.0%	1,897	1.0%
Domestic Time of Day	20	21	5.0%	22	3.3%	22	3.3%
Small General Service	224	222	-1.0%	222	0.2%	223	0.2%
General Service	189	189	0.0%	192	1.2%	194	1.2%
Large General Service	3	3	0.0%	3	0.0%	3	0.0%
Unmetered Loads incl Street Light	661	661	0.0%	661	0.0%	661	0.0%
TOTAL	**2,915**	**2,956**	1.4%	**2,978**	0.7%	**3,000**	0.7%
Energy - kWh	**Actual**	**Actual**		**Projected**		**Test Year**	
	2022/23	**2023/24**	**% Growth**	**2024/25**	**% Growth**	**2025/26**	**% Growth**
Domestic Standard	17,173,188	18,610,334	8.4%	18,698,235	0.5%	19,041,642	1.8%
Domestic Time of Day	374,390	417,482	11.5%	445,125	6.6%	462,512	3.9%
Small General Service	1,008,223	927,310	-8.0%	969,371	4.5%	961,430	-0.8%
General Service	11,922,756	12,181,717	2.2%	12,247,509	0.5%	12,397,740	1.2%
Large General Service	8,448,320	8,086,119	-4.3%	8,179,860	1.2%	8,272,808	1.1%
Unmetered Loads incl Street Light	155,226	155,226	0.0%	155,226	0.0%	155,226	0.0%
TOTAL	**39,082,103**	**40,378,188**	**3.3%**	**40,695,326**	**0.8%**	**41,291,357**	**1.5%**

3.1.1 Findings

[13] The Board finds that the load forecasts represent a reasonable estimate of future load. The Board notes, however, that there is considerable room for improvement in the utility’s load forecasts. The forecasts for domestic load rely entirely on past usage and HDD data. The Board has observed that the equations used have an inverse relationship between average kWh and HDD. For example, the Test Year shows HDD declining yet the average kWh is increasing. Relying solely on HDD ignores important elements of the load such as heat pumps, cooling demand, electric vehicles and energy efficient appliance uptake (particularly if there are renovations or new housing developments). While the Board is sensitive to the challenges smaller utilities have in acquiring data and forecasting, the utility needs to pay stronger attention to its underlying assumptions and the changes that are occurring in the industry.

3.2 Revenue Requirement

[14] As noted, the utility is requesting approval of a revenue requirement of $8,895,622 for the Test Year. This is made up of the following:

Purchased Power	$6,325,911
Operating, Maintenance, and Administration	$1,556,517
Depreciation	$427,162
Financial Costs	$586,031
Total	**$8,895,621***

* Difference due to rounding

3.2.1 Purchased Power

[15] The utility purchases all its electricity from NS Power, under that utility's approved municipal tariff. This is the utility's largest expense. Its purchased power costs in the Test Year are projected to be $6,325,911, or approximately 71% of its requested revenue requirement.

[16] Ian Lightstone, a Nova Scotia resident and one of the utility's customers, spoke at the public hearing about the cost of obtaining service from NS Power. Mr. Lightstone asked the Board to deny the utility's request for an increase of approximately 11% to the Domestic Standard Service class rate. This was not because he questioned the utility's need for additional funding, but because he considered that NS Power's charges to municipal electric utilities and their customers should be reduced.

[17] Mr. Lightstone submitted that Emera's CEO and board members are overcompensated relative to organizations he considered comparable, such as Hydro One, Ontario Power Generation, and Hydro Quebec. Likewise, he submitted NS Power's CEO and board members are overcompensated compared to Alectra Utilities, Elexicon

Energy, Hydro Ottawa, and Toronto Hydro. Generally, Mr. Lightstone questioned why Nova Scotians would pay more for people in these positions at Emera and NS Power when electricity rates are higher in Nova Scotia than in other jurisdictions and the system here is not more technologically advanced or cleaner than in those other jurisdictions. In closing, Mr. Lightstone said the Board should go back to Emera and NS Power and ask them to tighten their belts. In essence, he said they should “eat the proposed rate increase to Lunenburg households.” He said they should reduce the compensation of their CEOs and boards as a starting point.

3.2.1.1 Findings

[18] Although the utility’s last general rate application was in 2013, it has made regular flow through adjustments to pass along increases in the rates that NS Power charges for its supply of electricity since that time. As such, NS Power’s rates for electricity are not the proximate cause for the overall 16.7% increase in the utility’s revenue requirement in this proceeding.

[19] The purchased power costs included in the utility’s revenue requirement are paid at rates approved for NS Power. NS Power’s costs are reviewed in general rate applications in a public process that typically involves many intervenors. The appropriateness of NS Power’s costs is always a fundamental issue in these proceedings. The NSUARB’s most recent decision approving NS Power’s current rates was released on February 2, 2023 (2023 NSUARB 12).

[20] The Board notes that the costs of Emera’s CEO and board members are not directly included in NS Power’s revenue requirement but would be funded in part from the return on investment NS Power’s shareholder (Emera) is entitled to under the *Public Utilities Act*. Compensation paid to NS Power’s executives is a relevant issue that has

been explored in many NSUARB decisions in the past. This is expected to continue before this Board in the future. However, the issue of executive compensation is affected by the *Nova Scotia Power Incorporated Regulations*, NS Reg. 231/2012. Under these regulations, the amount of compensation for NS Power's CEO and its other executives that is allowed to be included in NS Power's approved rates is capped by government at specified percentages of the compensation paid to senior provincial government officials. Compensation paid to executives above these amounts must again be funded through NS Power's allowed return on investment.

[21] Given the foregoing, the Board finds it is appropriate for the Lunenburg utility to include its costs for the electricity it buys from NS Power in its revenue requirement and recovered through the rates it charges its own customers.

3.2.2 Operating, Maintenance, and Administration

[22] After purchased power costs, the next highest category of expenses for the utility is its operating, maintenance, and administration costs. At a projected amount of $1,556,517 in the Test Year, these costs contribute 17.5% to the proposed revenue requirement.

[23] As explained in the rate study and shown in the "OM&A Functionalization" tab in Exhibit L-1(iv), most costs for the Test Year were estimated as an approximate 4% increase over the projected costs for fiscal year 2024/2025 at the time the application was prepared. The utility noted that this was based on the Nova Scotia Consumer Price Index for 2023, which was the last completed year available when the rate application was being prepared.

[24] Distribution Superintendence and Overhead costs were an exception. These costs were estimated to increase 24%, based on costs projected by NS Power

under its contract for maintenance and other services with the utility. In its response to Undertaking U-6 [Exhibit L-9], the utility explained that this extraordinary increase is due to the funding of an additional resource under its services contract with NS Power. The position began halfway through the fiscal year before the Test Year and requires an increase in the Test Year to fully reflect the costs for the new position.

3.2.2.1 Findings

[25] The Board finds that the operating, maintenance, and administration costs are reasonable and accepts them as filed. The utility justified the additional Distribution Superintendence and Overhead costs and its approach to forecasting all other costs. The Board encourages the utility 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.

3.2.3 Depreciation Expense

[26] The calculation for the depreciation expense is shown in the “Exhibit 1-2 Net Plant” tab in Exhibit L-1(iv). All of the utility’s classes of assets are depreciated at a rate of 3.5% per year. This simplification was allowed by the Board in prior proceedings and may warrant reconsideration in the future.

[27] The projected costs of $105,000 to prepare and present this rate application were proposed to be capitalized by the utility and recovered over two years, rather than 3.5% per year.

3.2.3.1 Findings

[28] The Board is concerned that the 3.5% depreciation rate may no longer be appropriate. The utility is planning future capital expenditures that are considerable. At the same time, it is facing upward pressure on its rates. The Board is not opposed to

a simplified method to calculate depreciation for smaller utilities, but with time and changes to the magnitude of the utility's capital investment patterns, the approach should be reviewed. Therefore, the Board directs the utility to consider whether the continued use of a global depreciation rate of 3.5% remains appropriate in its next general rate application.

3.2.4 Financial Costs

[29] Financial costs are comprised of the following:

Debt Repayment - Interest	$27,800
Dept Repayment - Principal	$133,000
Owner Return	$425,231
Total	**$586,031**

[30] Interest and principal repayment on debt is based on projected actual costs. The owner return is a proposed return on rate base of 5.4%, which is based on a deemed capital structure of 60% debt and 40% equity, with a deemed interest rate of 4% and return on equity of 7.5%. In recent general rate applications filed by the Riverport Electric Light Commission (2023 NSUARB 56), Town of Mahone Bay (2023 NSUARB 66), the Berwick Electric Commission (2023 NSUARB 207) and the Town of Antigonish (2024 NSUARB 79), the NSUARB allowed the utilities to recover a return on rate base of 4.8%, based on a deemed capital structure of 60% debt and 40% equity, a cost of debt of 3% and return on equity of 7.5%.

[31] In its response to Board staff information requests in this case, the utility set out its justification for its requested rate of return:

TOLEU considered two factors affecting its request for rate of return. One is the equity risk premium (difference between the cost of debt and cost of equity); and the other is the level of business risk.

In recent previous municipal utility cases before the Board, the utilities requested essentially a deemed interest rate, given that they had no intention to do significant borrowing. In the case of TOLEU, its planned capital program in the test year and the following four years is large relative to the existing rate base, and will require borrowing, potentially up to a significant portion of its capital structure. The currently quoted rate is 4% from its funding source, as compared with the 3% allowed by the Board in the cases of the Berwick and Antigonish utilities.

TOLEU reviewed the forecast for interest rates posted by TD Bank, which is provided below. On the basis of a four-quarter average, 10 year rates are being forecast to decrease slightly from 2024 (the timing of the rate decisions for the other utilities) to the current year, from 3.28% to 3.09%, and 30 year rates are forecast to remain essentially the same, averaging 3.30% for 2024 and 3.36% for 2025. For 2026, the Bank forecasts 3.00 percent for 10 year, and 3.30 percent for 30 year funds. On this basis, TOLEU does not expect that the rate at which it can expect to borrow will decline from current levels during the remainder of the test year.

If the Board allows TOLEU to cost its debt at 4%, a 7.5% return on equity would represent a reduction in the equity risk premium from the level allowed to the other utilities.

TD Forecasts Financial Markets Economy Future Ready Economy Media

Interest Rate Outlook

Interest Rates	Spot Rate	2024				2025				2026			
	May-08	Q1	Q2	Q3	Q4	Q1	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
CANADA													
Overnight Target Rate	2.75	5.00	4.75	4.25	3.25	2.75	2.50	2.25	2.25	2.25	2.25	2.25	2.25
3-mth T-Bill Rate	2.64	4.99	4.64	3.96	3.16	2.62	2.38	2.25	2.25	2.25	2.25	2.25	2.25
2-yr Govt. Bond Yield	2.55	4.17	3.99	2.91	2.93	2.46	2.61	2.40	2.35	2.35	2.35	2.35	2.35
5-yr Govt. Bond Yield	2.76	3.51	3.51	2.73	2.96	2.61	2.84	2.85	2.80	2.75	2.75	2.75	2.75
10-yr Govt. Bond Yield	3.15	3.45	3.50	2.95	3.23	2.97	3.23	3.10	3.05	3.00	3.00	3.00	3.00
30-yr Govt. Bond Yield	3.47	3.37	3.37	3.14	3.33	3.23	3.45	3.40	3.35	3.30	3.30	3.30	3.30
10-yr-2-yr Govt Spread	0.60	-0.72	-0.49	0.04	0.30	0.51	0.62	0.70	0.70	0.65	0.65	0.65	0.65

https://economics.td.com/ca-forecast-tables

TOLEU also has concerns about its level of business risk, in the face of current tariffs and tariff threats from the United States as well as actions that may be taken in response by the Government of Canada. These are anticipated to lead to slower growth and greater uncertainty. A variety of sources are predicting a recession in Canada. The Bank of Canada has expressed concerns about increasing levels of mortgage late payments or defaults.

While TOLEU is not directly involved in trade with the United States, it would be affected if these events and policies create hardship for TOLEU's domestic and business customers. TOLEU submits that in this economic climate, its level of risk is at least as great as what it, or other Nova Scotia municipal utilities, faced in 2023 and 2024, if not greater.

It is therefore requesting approval of the same equity return of 7.5% as that approved for other municipal utilities by this Board.

[Exhibit L-4, IR-15]

[32] In terms of the proposed cost of debt, the utility said it used 5% when its budget was first prepared, based on Municipal Finance debenture pricing from the spring of 2024. However, when its general rate application was prepared, the fall 2024 and spring 2025 debentures were also available for reference and suggested to the utility that a 4% cost of debt would be more appropriate.

[33] In Exhibit L-4(v), the utility notes its outstanding principal balance on existing debt in the Test Year is $200,000, half of which will be paid in the Test Year. The balance will be paid in the following year, retiring the existing debt. The utility also proposes to borrow $500,000 in the Test Year.

[34] Although the utility said its planned capital program in the Test Year and the following four years is large relative to the existing rate base, and will require borrowing, potentially a significant portion of its capital structure, the Board notes that the utility's actual capital structure will continue to be far less than 60% debt in the Test Year. A total amount of debt of $700,000 represents about 8.3% of the $8,389,465 rate base in the Test Year. At the hearing, the utility's consultant, Ms. Zarnett, agreed this was a limited amount of debt, similar to the circumstances relating to the other municipal electric utilities.

[35] The utility projects its debt will increase to approximately $3.2 million in the year after the Test Year. While this is significant, it is still less than 60% of the Test Year rate base (which is also likely to grow in the following year due to capital additions net of depreciation).

[36] Additionally, while the utility's proposed net income is calculated by removing interest payments on long term debt from the proposed return on rate base, it

does not account for principal payments on long term debt. As noted in the utility's response to Board staff IR-17, if the recovery of principal payments in the Test Year were to be considered to be an additional return on rate base, the total return on rate base would be 6.99%.

[37] At the hearing, Ms. Zarnett agreed that allowing the recovery of principal payments on debt in a revenue requirement was unusual. However, it was requested by the utility in this case because that is what the Board allowed in its last general rate application.

3.2.4.1 Findings

[38] 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. Although municipal electric utilities in the province have not historically claimed a rate of return in a formal sense, all five municipal electric utilities have asked for one in the general rate applications they recently filed, beginning with the Riverport Electric Light Commission application, decided by the NSUARB in April 2023.

[39] None of these applications involved a formal cost of capital study or other evidence from qualified cost of capital experts. In all previous cases over the past two years, the NSUARB determined that a cost of debt of 3% and a return on equity of 7.5% on a deemed capital structure of 60% debt and 40% equity was appropriate.

[40] The deemed capital structure warrants some comment. Generally, the municipal electric utilities have carried relatively little debt. If the cost of capital were to be determined on the actual debt-to-equity ratio of the utility, the overall return on rate base would be relatively high given the increased weight that would be given to the equity rate. In the Board's view, and without formal cost of capital evidence to suggest otherwise, this

would be an unreasonable burden on ratepayers. The deemed capital structure is intended to result in an overall return on rate base that is reasonable.

[41] In this case, the utility argued that other municipal electric utilities were not doing any significant borrowing and had only a deemed interest rate whereas Lunenburg has a relatively large capital program with an expected rate of 4%. The Board accepts the 4% interest rate but the argument advanced by the utility in this case assumes a degree of precision in setting the overall rates of return for its comparators that does not exist.

[42] The utility's actual debt in the Test Year in this case is not even remotely close to the 60% deemed debt level in its capital structure (as was also the case with the other municipal electric utilities). As such, the debt rate serves as a notional offset to the rate of return on equity to produce a rate of return on rate base the Board considers reasonable in the circumstances and in the absence of more reliable cost of capital evidence.

[43] Likewise, while the utility argues that its risk premium may be greater than other municipal electric utilities, the Board has very little evidence before it to confirm whether that risk premium is higher or lower.

[44] Given the general way that the return on rate base was established for the other municipal electric utilities in their recent general rate applications, the Board also considers it would be reasonable for the return approved in the present application to be consistent with the overall return allowed in the other recent cases. As such, the Board approves the same cost of debt of 3% and sets a return on equity of 7.5% on a deemed capital structure of 60% debt and 40% equity, as the NSUARB approved for the

other municipal electric utilities in their recent applications. This produces the same rate of return on rate base of 4.8%.

[45] The Board appreciates that a cost of capital study similar to the one filed by NS Power in its last general rate application would be a significant undertaking for a small utility and would likely cost more than any incremental benefit the utility might expect relative to the outcome in this case. By the same token, the Board must ensure that what is claimed by the utility is just and reasonable from its ratepayers' perspectives.

[46] Additionally, the Board finds that continuing to allow the utility to recover its principal payments as well as a formal return on rate base is not appropriate. This is not consistent with the general approach to rate regulation, as accepted by Ms. Zarnett. A utility's return of the capital it invests in its assets is generally accomplished through an allowance for depreciation in its rates. To allow the recovery of both depreciation and principal payments could be considered a form of double recovery.

[47] The Board notes that the NSUARB (and now the Nova Scotia Regulatory and Appeals Board) has traditionally allowed the small water utilities in the province to include depreciation costs and principal debt payments in their revenue requirements and recover these costs through utility rates. However, these utilities do not seek a formal rate of return and, while a notional return on rate base is calculated, the return is comprised of the recovery of non-operating expenditures (including principal payments) less non-operating and other revenues.

[48] The Board directs the utility to remove the separate recovery of principal payments from its revenue requirement in a compliance filing.

[49] That said, the Board notes that small utilities like the one operated by the Town of Lunenburg may require some flexibility to ensure their continued viability. If the utility proceeds with the capital plan it presented in this application over the next few years, it will be important to ensure that it has the cash flow to pay its debts as they come due and to ensure that the utility retains some capital to invest in normal operations. Recovery through depreciation may not fully satisfy these requirements, and departures from general principles may be appropriate and justifiable on a case-by-case basis, supported by specific evidence in a future rate application.

[50] As a final comment, the Board notes that, in its application, the utility used a 5% rate of interest for the $500,000 debenture it anticipates in the Test Year. In response to Board staff IR-12 [Exhibit L-4], the utility indicated it would adjust its estimate to 4% in a compliance filing, which is acceptable to the Board notwithstanding the Board's direction to use a 3% debt rate in determining its return on rate base under its deemed capital structure.

[51] Changes to the revenue requirement resulting from the Board's approval of a lower rate of return on rate base and the interest adjustment noted by the utility in its response to Board staff IR-12 must be included in the utility's compliance filing.

3.2.5 Storm Costs

[52] In recent general rate applications brought forward by other municipal electric utilities in the province, the NSUARB considered it would be prudent to track storm costs to assess whether they are increasing. The Board directs the Town of Lunenburg to do so as well.

3.3 Capital Costs

[53] The utility said it needs to undertake an extensive capital expenditure program over the next few years. It has recently added a voltage regulator for approximately $250,000 and, when it filed its application, projected $885,000 in capital expenditures in 2024/2025. It said it has plans for approximately $3.24 million in capital spending in the Test Year (the breakdown for which was provided in the rate study [Exhibit L-1(i), p. 8 and "Exhibit 1-1 Gross Plant" tab in Exhibit L-1(iv)]. Its five-year capital program contemplates approximately $14 million in capital spending (with a breakdown provided in Exhibit L-4(iv)). The utility provided additional information about specific categories of capital expenses in response to Board staff information requests.

[54] The utility also proposed to capitalize its costs of this application, estimated at $105,000, and recover them over a two-year period.

3.3.1 Findings

[55] The Board considers the estimate of the capital plan for the Test Year to be reasonable for establishing the Test Year revenue requirement. However, the Board reminds the utility that the review of proposed capital spending in a general rate application does not result in the approval of specific capital projects. Separate approval is required for each capital project over $250,000 under s. 35 of the *Public Utilities Act*. The Board notes that in Matter M12147, the Board recently approved capital spending by the utility in the amount of $2.373 million on distribution system improvements near Kissing Bridge Road and Green Street.

[56] The Board also approves the utility's request to capitalize its costs for this rate application and recover them over a two-year period beginning in the Test Year.

3.4 Working Capital

[57] The utility is requesting approval of a working capital allowance of $788,243. This amount is based on an estimated 36 days payment lag (10%) applied to its forecast of $7,882,428 in net cash expenses (operating expenses less depreciation). The amount of working capital approved for the utility in its last general rate application was $400,000, which was approximately 7.5% of its net cash expenses at that time. However, the analysis submitted in its last application was not specific and the utility suggested that increases in power purchase costs could potentially justify working capital in the $500,000 to $600,000 range.

[58] The utility has not performed a lead-lag study to estimate its required working capital. Instead, it submitted its request as reasonable based on the Board's previous approval of a 10% allowance for other municipal utilities in their recent general rate applications, and the approach taken by the Ontario Energy Board, which for many years has established a default level of working capital that municipal utilities can claim without a supporting lead-lag study.

3.4.1 Findings

[59] 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 the utility's motivation to review its operations to find efficiencies. Without a lead-lag study the Board has some concerns about the reasonableness of the requested working capital amount but will allow the utility to use 10% of net cash expenses in this proceeding.

[60] The Board understands the potential costs involved in a lead-lag study for the utility. However, the Board expects some assessment based on utility specific

information to be included in the next general rate application. Alternatively, the Board encourages the utility 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.

3.5 Cost Allocation

[61] Board Counsel consultant, Mr. Havumaki, reviewed the rate study filed in this application. In his evidence, Mr. Havumaki found that, overall, the utility's cost allocation methods are sound. He said the cost allocation approach was thorough, and that the utility's methodological approaches were reasonably supported. However, Mr. Havumaki did express some concern about the utility's approach to estimating each class's coincident and non-coincident peaks.

[62] Mr. Havumaki noted that the utility does not have hourly load data for its customers, so it uses monthly sales data along with individual customer monthly peak demand for each General Service class and Large General Service class customers. The approach varied by customer class, as described by Mr. Havumaki in his evidence:

> Because TOLEU does not have detailed customer load data, the utility uses a mixed approach with multiple data sources to estimate the coincident peak (CP) and non-coincident peak (NCP) contributions for each class. For the General Service classes, TOLEU combines limited metering data with known load characteristics of analogous customer classes from similar utilities and assumptions about the relationships between total billed demand, NCP, and CP. TOLEU estimates the unmetered class's NCP and CP using known characteristics of these loads in consideration of the time of system peak. The Domestic class CP is a residual difference from the system CP and the other classes' CP. TOLEU then derives the Domestic class NCP from this residual CP.
>
> [Exhibit L-5, p. 6]

[63] Mr. Havumaki went on to note that the coincident peak for the General Service and Large General Service classes was estimated using two "diversity adjustments". The first adjustment estimates the simultaneous peak demand for all

General Service customers as a whole in the month that the system peak occurs. The second adjustment reflects the timing difference from when the total distribution system coincident peak occurs, and the timing of the General Service customer class peak demand. Mr. Havumaki expressed particular concern that the second adjustments for the General Service and Large General Service classes were different. He stated that the use of a 95% diversity factor for the second adjustment for the Large General Service class potentially overestimates this class's responsibility for coincident peak related costs to the benefit of the Domestic Service class, whose coincident peak was calculated as the residual of all other class's summed coincident peaks.

[64] Mr. Havumaki said the utility's justification for using a different adjustment than the 85% diversity factor used for the General Service class was not fully justified given that both classes were assumed to have flat demand during business operating hours. He recommended that the Large General Service class adjustment be changed from 95% to 85% to match the General Service class adjustment. He noted this would produce a coincident peak to non-coincident peak ratio for the Large General Service class that was similar to a comparable customer class served by the similarly sized Berwick Electric Commission, which had been determined using actual hourly meter data. He also recommended that the utility install new meters with hourly metering capability for the Large General Service class customers at least one year in advance of the utility's next general rate application to collect more detailed information.

[65] In its opening statement for the hearing, the utility submitted that adjusting the diversity factor for the Large General Service class, as recommended by Mr. Havumaki, would still produce rates for this rate class within the Board's traditional

95% to 105% revenue-to-cost ratio. The utility submitted it was not clear such an adjustment was required at this time. The utility accepted the recommendation to install meters with hourly metering capability for customers in this class and undertook to do that before December 31, 2025, in advance of the coming winter.

[66] Mr. Havumaki also expressed some concern about the utility's approach to classifying some of its distribution system costs upstream of the customer service drop. He noted the utility classifies conductors, poles, and fixtures as 70% demand-related and 30% customer-related. Mr. Havumaki recognized that this issue arose in the recent general rate applications of the other municipal electric utilities in the province, and that the Board permitted these utilities to use this approach, subject to reconsideration in the future and potential study in a NS Power general rate application. Mr. Havumaki said this classification had relatively little impact in the current proceeding, but it could have more impact as the utility proceeds with its proposed capital plan.

3.5.1.1 Findings

[67] The Board accepts the concerns raised by Mr. Havumaki about the discrepancy between the diversity factors used to determine the coincidental peak for the General Service and Large General Service classes. As Mr. Havumaki noted, it is logical to assume that both rate classes would have relatively flat demands during business operating hours. However, without specific data, it is difficult to know whether an assumption of an 85% diversity factor versus a 95% diversity factor is superior.

[68] The utility's undertaking to install meters with hourly metering capability for the customers in the Large General Service class should provide better data to assess the class load shape for cost allocation purposes in the utility's next general rate application. Given that this application is expected to occur within two years, the fact that

the Large General Service class is made up of three customers described as institutional with 24/7 operations, and the class demand is primarily determined by one of them, the Board is inclined to defer to the utility's judgment on this point, at least for the time being. The Board directs the utility to discuss this issue in more detail, with the benefit of more granular metering data, in its next rate application.

[69] As for the distribution system upstream of the customer service drop, the Board is of the view, as expressed by the NSUARB in recent cases involving other municipal electric utilities, that a fundamental change to the utility's historical method of allocating its distribution system costs is not appropriate at this time and there is value in ensuring some underlying consistency in the costing methodologies used amongst local electrical utilities, especially the smaller municipal utilities. This issue may be one that is more thoroughly considered when NS Power completes its next cost-of-service study, and that may inform a go-forward approach for the municipal electric utilities on this point.

3.6 Rate Design

[70] The utility has not performed an in-depth review of rate design in this application. Except for a small number of specific rate design considerations, it proposes continuing with the design of the rates as they currently exist.

3.6.1 Domestic Standard Service

[71] The existing Domestic Standard Service rate has a base charge and an energy charge. The energy charge has two tiers or blocks. A somewhat higher energy charge applies to a customer's first 200 kWh in a month, and a somewhat lower charge applies to the rest of the customer's consumption in the month. The utility proposed two changes to the existing rates, both to be consistent with certain findings and comments

in the NSUARB's recent decisions about the general rate applications for the other municipal electric utilities.

[72] The first change is an adjustment to the base charge to reflect customer-related costs consistent with the Board's directions in some of these recent cases. The second change is to eliminate the two-block structure of the energy charge so that there is one uniform energy rate that is charged to the customer for all the energy they consume.

3.6.1.1 Findings

[73] The Board approves the proposed changes to the base charge and the elimination of the two-block rate structure.

3.6.2 Domestic Service Time of Day Formula

[74] As noted previously, the Domestic Service Time of Day rate is determined by a formula with reference to the Domestic Standard Service rates. The rates charged during peak hours in the winter months (7 AM to 1 PM and 4 PM to 10 PM in December, January and February) and during the "shoulder" periods (1 PM to 4 PM in the winter months and 7 AM to 10 PM from March to November) were based on the Domestic Standard Service class "tail block rate". The rate in the shoulder periods was equal to the tail block rate, while on-peak charges were twice that rate.

[75] With the elimination of the two-block structure for the Domestic Standard Service class, the uniform energy rate for the Domestic Standard Service class will be used. The utility notes that this change may have some impact on the percentage increase for this class in this application but it has not invested the resources to review this more complicated rate structure. The utility also proposed to increase the base

charge for this class by the same percentage increase as the adjustment to the base charge for the Domestic Standard Service class.

3.6.2.1 Findings

[76] The Board approves the proposed changes to the base charge and the use of the uniform Domestic Service Class energy rate in the formula. The Board directs the utility to modify the tariff language to reflect this change in its compliance filing.

3.6.3 Declining Block Rate Structures – General Service and Large General Service Classes

[77] The utility's General Service and Large General Service classes also have two-block rate structures, but the utility did not propose to eliminate these in this application. Mr. Havumaki recommended that the Board direct the utility to evaluate whether there is any cost-based reason for retaining the declining block rate structure for these rate classes in its next rate study and to eliminate these structures if the evidence did not show a cost basis for retaining them. In its opening statement, the utility said it supports the recommendation to evaluate phasing out the declining block rate structure for the General Service and Large General Service classes in its next general rate application.

3.6.3.1 Findings

[78] The Board agrees with Mr. Havumaki's recommendations and directs the utility to evaluate the block structure for the General Service and Large General Service classes by the next rate hearing and provide recommendations and options for their elimination, or a justification for retaining them, at that hearing.

3.6.4 Demand Charges

[79] The utility's General Service and Large General Service class rates also include a demand charge. It has been some time since these rates were adjusted other than by way of a percentage increase to recover overall cost increases allocated to these rate classes. Over time, overall percentage increases can potentially skew the proportion of demand and energy charges paid by customers. In response to Board staff IR-47, the utility provided information suggesting that the revenue projected to be obtained from demand charges to the Large General Service class was under recovering relative to the demand-related costs allocated to this rate class. At the hearing, Ms. Zarnett agreed that the discrepancy should be looked at in the next hearing.

3.6.4.1 Findings

[80] The Board is concerned that the demand charges may be causing subsidization between customers in the affected rate classes. It directs the utility to evaluate the demand charges for General Services and Large General Services, and their recovery rate relative to costs, and to bring forward the results of that evaluation and any appropriate recommendations to the next rate hearing.

3.6.5 Streetlights and Yard Lights

[81] The utility noted that it had converted the inventory of streetlights in the Town of Lunenburg to more efficient LED lights and privately owned lights are being converted gradually, as they require replacement. However, the utility's existing rate schedule only includes rates for high pressure sodium lights. Currently, the utility charges rates for LED lights at the rate approved for a comparable high pressure sodium light. The utility proposes to restate its rate schedule to reflect an updated inventory of lights.

[82] In response to Undertaking U-5 [Exhibit L-9], the utility provided a listing of its high-pressure sodium and LED lights, but it did not provide updated wording for the rate schedule with associated proposed rates.

3.6.5.1 Findings

[83] The Board directs the utility to provide an updated "Street and Yard Lighting" section for Schedule A – Schedule of Rates for Electric Supply and Services in its compliance filing. The update should specify the rate for each type of LED, as well as for any other lights the utility rates.

3.7 Rates and Charges

3.7.1 Revenue-to-Cost Ratios

[84] The predecessors to this Board have traditionally considered that rates that are set to recover revenue within a range of 95% to 105% of the costs allocated to a particular rate class are reasonable. The NSUARB discussed the basis for this in a decision that considered a proposed rate for NS Power's extra-large industrial interruptible customers:

> [85] Electricity rates are set on the basis that the costs incurred by the utility to serve its customers, together with a reasonable rate of return, are recovered from its customers. Customers are divided into customer classes. These classes reflect variations in the services required by different customers (e.g., domestic customers and industrial customers) which are received from the utility. Since the services required by each customer class differ, the utility's cost to serve each customer class also differs. For example, in order to serve domestic customers, the utility must have an extensive distribution system. Large industrial customers do not require this infrastructure and, therefore, the costs to serve these two classes of customers are quite different. As a result, the total revenue requirements of the utility must be fairly divided by customer class and allocated accordingly. The requirement for fair allocation of costs ensures that all customers pay for the cost of the service they receive and their rates do not subsidize the rates of other customers.
>
> [86] This cost allocation is performed by using a cost of service study prepared by the utility which identifies the costs attributable to each customer class. In 1995, the Board approved the cost of service methodology currently being used by NSPI. The approval was based on the Board's conclusion that this particular cost allocation methodology produces fair and reasonable electricity rates for all customers. Since it is virtually impossible to allocate customer costs over time with 100% accuracy, the Board has long

> accepted that an R/C ratio between 95% and 105% is an appropriate basis on which to set rates. As long as the R/C ratio falls within the target range of 95% to 105%, the Board is satisfied that all customer classes are being treated fairly and no customer class is receiving a preferential or subsidized rate at the expense of others. Indeed, the Board has approved rates where the R/C ratio for one or more classes is outside the 95% to 105% range where this has been necessary to achieve rate stability.
>
> [2006 NSUARB 97]

[85] Based on the costs allocated in the rate study filed in this matter and prior to any adjustments, the only rate class under existing rates that is within the 95% to 105% range in the Test Year is the Domestic Time of Day customers. The other classes are below the range. Under current rates, the utility would only be recovering about 86% of its revenue requirement.

[86] The utility proposes adjustments to rates in this application that would result in all rate classes, except the Domestic Time of Day class and the General Service class, falling within the generally accepted range. The Domestic Time of Day class is proposed to be approximately 110% and the Small General Service class is 87%. The utility provided a detailed explanation for how it arrived at its proposal in response to Synapse IR-19 [Exhibit L-3].

[87] The utility described its process for allocating revenue increases as iterative and guided by three constraints or targets:

1. the total revenue from all classes equals the revenue requirement;
2. the proposed electricity rate increases do not constitute rate shock for any customer class; and
3. each customer class has a revenue-to-cost ratio within the Board-approved range of 95% to 105%.

[88] The utility determined that a uniform increase across all rate classes would not be appropriate because the resulting revenue-to-cost ratios would be much too low for street lighting and all the general service group of classes, and too high for

domestic customers. It elected to increase the rates for unmetered loads (mostly streetlighting) because the Town of Lunenburg itself was the customer for most of this class of service and this would flow revenue responsibility away from metered customers to some extent.

[89] The utility then examined how the remaining revenue requirement could be recovered. It considered the minimum amounts that would bring customer classes into the Board's generally accepted revenue-to-cost range. It said this required a 19% increase for the Large General Service class and a 32% increase for its Small General Service class. The utility considered a 19% increase for all general service classes, which produced a revenue-to-cost ratio for the Domestic Service class of 104%, near the top of the range. The utility considered this less desirable because it felt it would be fairer to add slightly to the increases for the general service classes so that all classes were slightly closer to the middle of the Board's range. The utility said it also wanted a general service increase that would be a significant step for the Small General Service class toward the Board's range.

[90] The utility considered several alternatives. It eventually landed on a 21% increase for the general service classes, which produced the following revenue-to-cost ratios and rate changes:

Revenue-to-Cost Ratios							
Rate Class	Total	Domestic Standard	Domestic Time of Day	Small General Service	General Service	Large General Service	Unmetered Loads including Streetlights
R/C Ratio	100%	102%	110%	87%	99%	97%	105%
Rate Change	16.7%	11.3%	9.6%	21.0%	21.0%	21.0%	38.7%

[91] The utility noted that, under its proposal, the domestic classes were receiving less than the system average increase. Although the Domestic Time of Day rate is above the Board's range, this rate is based on a formula using the Domestic Standard class rate. It said the only option to correct this would be to redesign the rate to uncouple it from the Domestic Standard rate.

[92] The utility also noted that although the Small General Service class is below the Board's range, the proposed increase of 21% is 126% of the system average increase, which it submitted was consistent with the thresholds for above system average increases the Board considered in recent municipal electric general rate applications. It said a choice is needed between immediately moving into the range (and raising the rate even higher) or not meeting the 95% threshold but protecting the customers from rate shock.

[93] To mitigate the 21% increase for the general service classes, the utility proposed to cap the amount of the increase recovered in rates to 15%. The difference would accrue in a deferral account that would be tracked by rate class and repaid by those rate classes in the future. At this point, the utility contemplates that by the time of its next general rate application, the rates for these classes will achieve full recovery. However, the duration of any rate added for the recovery of the deferred amounts has not yet been determined.

[94] Mr. Havumaki had two main concerns with the utility's proposed approach. He did not believe the utility sufficiently justified increasing the Domestic Service class above 100%, which he said would result in an "apparent subsidy" to general service customers. He also felt the proposed approach was too conservative given other

recent Board decisions, which used a 20% cap on rate increases (*Riverport Electric Light Commission* (2023 NSUARB 56) and *Town of Mahone Bay* (2023 NSUARB 66)).

[95] Mr. Havumaki proposed an alternative that phased in the revenue increases over two years. In the first year, he proposed to increase the Domestic Standard Service and Unmetered Service classes to a revenue-to-cost ratio of 100% and to cap increases to other rate classes at 20%. In the second year, the Small General Service class would be increased to a revenue-to-cost ratio of 95%, with the residual Test Year revenue requirement being recovered by increasing the rates of the other classes so that there would be a uniform revenue-to-cost ratio across these classes of about 100.1%. This proposal is shown in the two tables below from his evidence:

Table 2. First-Year Revenue Increases – TOLEU and Synapse Proposal[31]

	RCR at existing rates	First increase (TOLEU)	RCR after first increase (TOLEU)	First increase (Synapse)	RCR after first increase (Synapse)
Total	86.0%	*13.7%*	97.5%	*14.9%*	98.4%
Domestic	92.1%	*11.3%*	102.5%	*8.7%*	100.0%
Domestic TOU	100.8%	*9.6%*	110.4%	*7.5%*	108.2%
Small GS	72.3%	*15.0%*	82.8%	*20.0%*	86.3%
GS	82.3%	*15.0%*	94.4%	*20.0%*	98.4%
Large GS	80.4%	*15.0%*	92.2%	*20.0%*	96.2%
Unmetered	76.4%	*38.7%*	105.0%	*32.0%*	100.0%

[Exhibit L-5, p. 16]

Table 3. Second-Year Revenue Increases – Synapse Proposal

	RCR after first increase (Synapse)	Second increase (Synapse)	Cumulative increase (Synapse)	RCR after second increase (Synapse)
Total	98.4%	*2.09%*	*16.7%*	100.0%
Domestic	100.0%	*0.08%*	*8.6%*	100.1%
Domestic TOU	108.2%	*0.07%*	*7.3%*	108.3%
Small GS	86.3%	*9.0%*	*30.8%*	95.0%
GS	98.4%	*1.51%*	*21.8%*	100.1%
Large GS	96.2%	*7.32%*	*28.8%*	100.1%
Unmetered	100.0%	*0.08%*	*9.9%*	100.1%

[Exhibit L-5, p. 17]

[96] Mr. Havumaki noted that his alternative 20% increase cap in the first year was consistent with the NSUARB's decision in the recent Riverport and Mahone Bay general rate applications. It also results in a smaller deferral (about 18% smaller), which Mr. Havumaki noted has less impact on long-term costs and intergenerational equity (i.e., shifts fewer costs to future ratepayers). Mr. Havumaki also highlighted that his proposal would bring all rate classes into the Board's general revenue-to-cost range after two years, except for the Domestic Time of Day rate. As discussed earlier, the rate for this class is determined by a formula based on the Domestic Standard Service class rate.

3.7.1.1 Findings

[97] The Board finds that the rate adjustments proposed by the utility and the alternative proposal recommended by Mr. Havumaki are reasonable alternatives. Each has strengths and weaknesses. The utility's proposal favours gradualism for the more significantly impacted rate classes. The utility expressed considerable concern about the ability of its customers in those classes to bear more significant increases in the current economic climate. However, the utility's proposal leaves some rate classes outside of the Board's generally accepted range for reasonableness for cost recovery.

[98] Mr. Havumaki's proposal, on the other hand, brings all classes into the Board's generally accepted range (except for the formula-driven Domestic Time of Day Service class). However, the General Service and Large General Service rate classes would see even greater increases than the already significant increases proposed by the utility. In the case of the General Service Class increase, it approaches twice the system average increase. Other rate classes fare better under the Synapse proposal than under the utility's.

[99] Both proposals contemplate a deferral for the most significantly impacted general service classes. However, the Synapse proposal contemplates smaller deferrals, which mitigates the additional costs and intergenerational equity concerns arising from deferrals more than the utility proposal.

[100] Overall, the Board accepts the proposal advanced by the utility. It is not unreasonable, and while the Synapse proposal has some superior elements, the Board accepts the utility’s preference for gradualism in this case. However, the Board cautions the utility that this must be very carefully managed. In its next general rate application, there will likely be strong upward pressure on the overall rates for the Small General Service class in particular, due to the deferral of full increases in this application, the need to recover deferred balances, the desire to move this class within the Board’s general revenue-to-cost range, increased capital investment, and inflationary influences on the utility’s costs generally. Any delay by the utility in bringing its next general rate application may very well compound these problems.

[101] The Board notes that the reductions in the requested revenue requirement it is directing in other parts of this decision may have a bearing on the amount of the final rate increases and revenue-to-cost ratios, but it is not a straightforward adjustment from the approved revenue requirement to final rates given the iterative approach in setting rates described above. The Board directs the utility to apply a similar methodology to determine final rates from the approved revenue requirement in a compliance filing. The amount of the class increases and revenue-to-cost ratios should be explicitly noted in the compliance filing. The compliance filing should also detail the

utility's approach and justify any choices made in producing final rates and their corresponding revenue-to-cost ratios.

3.7.2 Deferred Recovery of Small General Service, General Service and Large General Service revenue

[102] As the Board discussed in NS Power's 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.

[103] The utility's proposal in this case was to set rates for the general service classes at a 21% increase, but to cap the amounts actually charged to those customers at 15% and recover the difference from those customers at a later point in time. The utility's plan for when the full amount of the 21% increase would begin to be charged to those customers (and deferrals would stop accruing) was vague. This was addressed at the hearing in questions from the Board to Ms. Dagley:

> Q. And in terms of the difference between the 15% and the 21%, Board Member Fisher or maybe it was Mr. Mahody had asked you some questions about when you intend to implement that. In the other cases, the other municipal electric utilities where there was a phase in of the rate increases, the part two was automatic. It came on without the utility coming back for further application or so on. I don't think that is the case here. You're proposing to phase that in when?
>
> A. Well, I guess what we were thinking was because we know that we might be doing another rate application in the next two years, there is a possibility that those might get combined, but that we wanted to see if economic conditions changed too, right, and just sort of keep an eye on that and bring it forward…
>
> Q. Okay,…
>
> A. …when we needed to phase that in.
>
> Q. …so the proposal then is to essentially allow that to run until the next general rate application?
>
> A. Perhaps.

Q. And at that point in time, rates would be set to the new cost of service for that particular rate class plus the recovery of the deferred amount?

A. That would be my assumption.

[Soundfile, 2:25:49 to 2:27:17]

3.7.2.1 Findings

[104] As noted, the Board accepts the utility's proposal for gradualism in this case, including the 15% cap for the general service classes as proposed. However, the cap (and the continuing growth of the deferred amount) cannot continue indefinitely. Although it is likely the utility will be seeking to adjust rates within a couple of years, there is no set date for that at this point and things may change.

[105] As discussed above, the lower revenue requirement the Board is approving in this proceeding will need to be translated into final rates by the utility following a similar methodology as outlined in its application and response to information requests. This may result in some modifications to the utility's proposed caps for the general service classes.

[106] As proposed by the utility, the approved rates for the general service classes will be temporarily capped, with the unrecovered amounts deferred for recovery later. The Board approves this cap until April 1, 2027, although the Board may remove it earlier, if requested to do so by the utility. Regardless, the utility is directed to provide customers who will be affected by the elimination of the cap at least two months notice before the end of the rate cap.

3.8 Changes to Fees

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

[108] For years, the utility maintained a pole attachment charge of $14.15, the same rate charged by NS Power before its last general rate application. The utility 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's 2023-2024 Rate Application, for the rate of $22.00 per year. The NSUARB approved a similar approach in other recent municipal electric utility general rate applications.

[109] The utility also proposed changing the permit and inspection fees in its *Schedule of Regulations Governing the Supply of Electric Service* to match NS Power's fees for these activities. The utility noted that NS Power provides these services to the utility under that utility's approved rates for these fees.

3.8.1.1 Findings

[110] The Board approves the updated fee of $22 for pole attachments and the proposed changes to the permit and inspection fees. The Board directs the utility to include the additional revenue associated with these fee changes in its compliance filing, if not already included in the rate study.

4.0 SUMMARY OF BOARD FINDINGS

[111] The Board directs the utility to submit a compliance filing addressing the Board's findings and directions in this proceeding, including:

a. removing the recovery of principal payments from the proposed revenue requirement;

b. adjusting the proposed revenue requirement to account for the Board's lower approved return on rate base;

c. making the interest adjustment identified by the utility in its response to Board staff IR-12;

d. modifying the tariff language for the Time of Day Service to reflect the elimination of the Domestic Standard Service class tail block rate;

e. modifying the tariff language for Street and Yard Lighting to show all types of lights in service and their corresponding rates;

f. accounting for the additional revenue associated with the fee changes for pole attachments, permits and inspections, if not already included in the rate study; and

g. developing final rate increases and revenue-to-cost ratios to reflect the reductions in the revenue requirement directed by the Board in this proceeding.

[112] The compliance filing should include updated rate study exhibits reflecting only the changes approved in this decision, along with revised tariffs (text and rates as appropriate), the approved regulations (removing the old effective date notes that were on the version filed with the rate application), and a narrative explaining the development of the final rates and revenue-to-cost ratios. The compliance filing must be submitted to the Board no later than September 11, 2025.

[113] The Board also directs the utility to:

a. track storm costs to assess whether they are increasing; and

b. provide customers in its general service classes with at least two months notice before the end of the rate cap.

[114] Additionally, in its next general rate application, the Board directs the utility to:

a. consider whether the use of a global depreciation rate of 3.5% remains appropriate;

b. provide some assessment of its working capital requirements based on utility specific information;

c. provide its Large General Service class customers with meters with hourly metering capability and discuss in its application the determination of the non-coincidental and coincidental peaks for the Large General Service class with the benefit of more granular metering data;

d. evaluate the block structure for the General Service and Large General Service classes and provide recommendations and options for their elimination, or a justification for retaining them; and

e. evaluate the demand charges for General Services and Large General Services, and their recovery rate relative to costs, and to bring forward the results of that evaluation and any appropriate recommendations to the next rate hearing.

[115] An Order will issue accordingly, upon approval of the compliance filing.

DATED at Halifax, Nova Scotia, this 28th day of August 2025.

Stephen T. McGrath

Jennifer L. Nicholson

Bruce H. Fisher