**DECISION** **2023 NSUARB 56**
**M10810**

## NOVA SCOTIA UTILITY AND REVIEW BOARD

**IN THE MATTER OF THE PUBLIC UTILITIES ACT**

- and -

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

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| **BEFORE:** | Stephen T. McGrath, K.C., Chair<br>Julia E. Clark, LL.B., Member<br>Bruce H. Fisher, MPA, CPA, CMA, Member |
| **APPLICANT:** | **RIVERPORT ELECTRIC LIGHT COMMISSION**<br>James MacDuff, Counsel |
| **INTERVENOR:** | **NOVA SCOTIA POWER INCORPORATED**<br>Blake Williams, Counsel<br>Rachel Petcoff, Counsel |
| **BOARD COUNSEL:** | David Roberts, Counsel<br>Michael Murphy, Counsel |
| **HEARING DATES:** | February 1 & 2, 2023 |
| **FINAL SUBMISSIONS:** | February 15, 2023 |
| **DECISION DATE:** | **April 13, 2023** |
| **DECISION:** | **Application is approved, effective the date of this decision, subject to changes and directions to be confirmed in a compliance filing.** |

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## 1.0 INTRODUCTION

[1] The Riverport Electric Light Commission (RELC) applied to the Nova Scotia Utility and Review Board to amend its Schedule of Rates for Electric Supply and Service and its Schedule of Rules and Regulations Governing the Supply of Electric Services. The utility's last general rate application was approved in October 2010. Since then, the Board has approved rate changes under RELC's flow-through mechanisms. The last change under that mechanism came into effect on January 1, 2019. There have also been some amendments to RELC's Rules and Regulations since October 2010.

[2] As filed, RELC's application proposed an overall average rate increase of 32.5%, including a 34.3% increase for all metered customer classes. RELC also proposed a 55% increase in its pole attachment fee, which was the only requested change to its Rules and Regulations.

[3] RELC's application also expressed concern that it may be liable to make payments for power purchased from NS Power in 2023 that RELC is not required to pay now but may, potentially, become liable to pay in the future. RELC says that it would not recover these future payments from its customers at that time because the costs would be for power purchased in the current period. To address this issue, RELC asked for approval to establish a deferral account for these notional future liabilities. If a balance accumulates in this deferral account, RELC would at some later date apply to the Board to recover this balance through rates or rate riders upon such terms as may be approved by the Board.

[4] A Notice of Hearing was advertised as required by the *Public Utilities Act*, R.S.N.S. 1989, c. 380 (*PUA*). The Board received several letters of comment (Exhibit

R-4). The Board did not receive any requests to speak at the evening session for the hearing, which was therefore cancelled.

[5] The hearing was held in Halifax and livestreamed on February 1 and 2, 2023. RELC's Manager, Nancy Bain, appeared before the Board and testified on behalf of the utility, along with Donald Regan, Superintendent of the Berwick Electric Commission and Aaron Long, General Manager of the Alternative Resource Energy Authority (AREA). RELC's consultants, Paula Zarnett and Trent Winstone, BDR NorthAmerica Inc., appeared virtually to support the utility's application. Board counsel consultant, Melissa Whited, Synapse Energy Economics, Inc., also testified virtually at the hearing. NS Power was represented at the hearing as an intervenor but filed no evidence, undertook no cross-examination, and made no submissions to the Board on the rate application.

[6] The Board approves RELC's application subject to the following:

- RELC must revise its revenue requirement to account for:
    - reduced power purchase costs from NS Power's approved rates;
    - removal of the proposed $15,000 for storm restoration;
    - the correction for the accounting treatment of contributed capital;
    - revenue from pole attachment fees based on the charge approved in this decision;
    - updated working capital based on 10% of the net cash expense after all the adjustments required by this decision; and
    - a return on equity of 7.5%.
- RELC's proposed rates are to incorporate the following cost-of-service and rate design changes:
    - classify transformer costs as 100% demand-related;

  - include meter costs in computing the ratio of classified distribution plant;
  - adjust rates using the three-step process recommended by Ms. Whited;
  - base customer service charge for Domestic Service on costs classified as customer-related in the cost-of-service study; and
  - the new tariff for a Cable TV Power Packs class is approved, with rates to be provided in the compliance filing.
- RELC's rate increases in 2023 are capped at 20% for each rate class in the first year, with rates being fully applied effective January 1, 2024, and with any unrecovered revenue from 2023 to be deferred for future recovery, upon application to the Board, beginning January 1, 2025, or as otherwise directed; and
- The Board has not approved RELC's requested deferral account for potential future liabilities, but approves the establishment of a deferral account with a more limited scope.

## 2.0 BACKGROUND

[7] RELC was created by an Act of the Provincial Legislature in 1920. It is governed by a five-person Commission, made up of representatives from the communities in its service territory.

[8] RELC is a distributing utility, supplying electricity service in Riverport, Lower LaHave, Rose Bay, and Kingsburg. RELC does not own or operate any electricity generation facilities. Primary distribution is through a 7.5/12 kV system, interconnected with the Nova Scotia grid. Wholesale electricity supply is purchased under multiple contracts with third parties, which it reviews regularly to obtain the best available pricing for the benefit of RELC's customers.

[9] The utility's system peak for 2023 is forecast at 2,784 kW on a weather-normalized basis. The customer base forecast for 2023 consists of 725 Domestic

Service, 131 Small General Service, 12 General Service and 1 Large General Service customer. Included in these are 30 Seasonal, 15 400-amp Domestic, 11 net metering and 11 Time- of-Use customers. In recent years, RELC has experienced modest but consistent growth in its customer base and total energy sales.

[10] RELC currently operates with three full-time cost-equivalent employees, consisting of one full-time manager, one part-time assistant, two full-time powerline technicians and one full-time apprentice. The powerline technicians and the apprentice are cost-shared with the Town of Mahone Bay Electric Utility on a 50/50 basis. The cost-sharing arrangement allows RELC to have dedicated qualified staff for the operation of its distribution system, despite the small size of the utility.

[11] In 2022, RELC commissioned an engineering review of its distribution system to identify needed capital expenditures over the next several years. The review identified that an investment to address a system supply constraint was urgently needed. After reviewing several options, RELC selected the installation of a voltage regulator as the lowest cost way to meet this need, at a cost of $78,500. RELC plans to complete this project in 2023, in addition to other capital projects totaling $276,000. RELC also identified capital projects needing to be carried out in the years 2024-2026, at an expected total cost of about $700,000. This work involves line upgrades and necessary replacements, including replacement of transformers with PCBs. These projects are considered urgent to maintain reliability and safety. RELC plans to fund capital expenditures for 2023 with new debt.

[12] In addition to the challenge of funding its capital budget, RELC faces the increasing cost of various supplies and services. Recently, in the context of escalating

fuel prices in the world markets, AREA sought new arrangements for RELC's wholesale supply of electricity. In 2023, RELC intends to purchase supply from NS Power at the rate for municipal customers approved by the Board. RELC estimated that, on an annualized basis per kWh, its cost of purchased power will increase by 41.9% in 2023 over the 12-month period and the utility is concerned that cost will continue to increase by a further unknown but significant amount in the year or years following.

[13] RELC concluded it could not continue to provide service at its currently approved rates without severe detriment to its financial health. As a result, through AREA, RELC commenced the process of preparing a Rate Study to make a general rate application to the Board.

[14] BDR prepared the Rate Study for this application and noted it is largely consistent with the methodology used in RELC's last rate GRA in 2010, with some changes. In an Information Request (IR) response to Synapse, BDR stated:

> This response refers to RELC's previous rate case filed in 2010. The current study is largely consistent in methodology with the prior study. Some changes were made based on the methodology preferences of the consultant, while others reflect the changing circumstances of the utility, such as sources of power supply and types of "other" revenues.
>
> The main refinements made to the study were therefore as follows:
>
> - Classification of transformers was changed from 100% demand to 70% demand, 30% customer, to recognize the effect of number of customers and density on the cost of line transformers.
>
> - Rather than using the same weighting for distribution customer-related costs and the costs of meters, metering and billing, separate weighting factors were developed by judgment and applied.
>
> - Financial costs (interest and net income) were explicitly identified and allocated by rate base. These were not previously identified separately in the study. Cost allocation studies in other Canadian utilities typically identify these costs as a line item in the revenue requirement, and allocated it according to rate base, since the allowed return is determined by rate base.
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> - New demand allocators were estimated. Any working papers used to estimate the 2010 demand allocators were not available for comparison with the current analysis.

- In 2010, the classification of purchased power reflected NSP rates only. In the current study, the rate structures for all power sources were included in the classification.
- Revenues other than for electricity sales were allocated to the classes separately for each type of revenue, according to the cost most related to the revenue. In the previous study, late payments were directly assigned, and all other revenues were allocated by rate base. Specifically, pole rental revenues were allocated by pole costs in the current study.

[Exhibit R-13, IR-2]

[15] As filed, RELC's application proposed a 34.3% rate increase for all metered customer classes, a 17.1% decrease in yard lighting rates, and no changes for street lighting and cable unmetered rates. The proposed overall average rate increase was 32.5%. In the application, the utility states it would realize an operating loss of $418,200 if it maintained current rates.

[16] The utility is requesting the following approvals in this application:

- The use of the calendar year 2023 as the test year, to enable new rates approved effective January 1, 2023, to meet the revenue requirement for the forecast calendar year.
- A revenue requirement of $2,062,240 for 2023, comprised of the costs shown in Exhibit R-6 (Exhibit 5).
- The accrual of all incurred and budgeted costs for advisors, legal counsel and Board costs related to this application into the test year and the recovery of such costs in the test year.
- A deferral account to reflect any liability associated with power purchases from NS Power commencing January 1, 2023, for which NS Power has or may receive approval from the Board to recover from RELC, for power purchased by RELC in and beyond the test year. If balances accumulate in this deferral account, RELC

would later apply to the Board to recover such balances through rates or rate riders upon such terms as may be approved by the Board.

- The Schedule of Rates and Charges as proposed in Tab I of its Rate Study (Exhibit R-1), or as amended to reflect the revenue requirement approved by the Board, to take effect for all electricity consumption or other services rendered on and after January 1, 2023.
- The Schedule of Rules and Regulations Governing the Supply of Electric Services included in Tab J of its Rate Study (Exhibit R-1).

## 3.0 DISCUSSION AND ANALYSIS

### 3.1 Calendar Year Test Year (2023)

[17] In calculating the revenue requirement for the test year, the utility used the January 1 to December 31 calendar year. However, the utility's fiscal year runs from April 1 to March 31. The utility was expecting NS Power's rates to take effect on January 1, 2023, and wanted the test year to coincide with the expected timing of NS Power's new rates. The utility stated that a potential consequence of requesting a fiscal year rate increase effective April 1 is not recovering the full year of cost-of-service, or higher rate shock by concentrating the recovery of the same costs over a shorter period.

[18] RELC indicated that its load and revenues were forecasted on a monthly basis, with both the calendar and fiscal year summing the respective 12-month periods. The test year expenses were forecasted using the same amounts as the budgeted fiscal year 2022/23, plus a $15,000 storm allowance added to operating and general expenses and $28,500 (50% of $57,000) for the cost of this rate application.

### 3.1.1 Findings

[19] The Board is concerned with the mismatching of the periods when developing the revenue requirement. The Board cautions RELC that selecting a test year that does not match the fiscal year can impede the clear presentation and reasonableness for its revenue requirement. Extra effort must be made to ensure that a clear picture of the changes in costs over time is presented.

## 3.2 Revenue Requirement

[20] RELC is requesting approval of a revenue requirement of $2,062,240 for the test year. This includes the total cost of purchased power, operations and maintenance costs, administrative and general costs, and amortization, plus $62,535. The $62,535 would cover interest on RELC's existing and new debt ($10,930), and net income of $51,605 based on a return on equity of 8%.

[21] Ms. Bain stated that other than flow-through increases between 2010 and January 2019, the utility has had no general rate increases in over a decade. She noted that the cost of fuel and purchased power has increased significantly because of global events. Further investments in RELC's infrastructure are also required in the near term to ensure the continued supply of safe and reliable electricity service. RELC deemed an increase in rates necessary.

### 3.2.1 Operating Costs

[22] RELC developed the forecast for its expenses in the test year using the same amounts in its budget for 2022/23 fiscal year ended March 31, 2023, plus the addition of a $15,000 storm damage budget and 50% of a $57,000 budget for the cost of this application. The RELC 2022/23 fiscal year budget included a 5% increase from the

prior fiscal year 2021/22 in its administrative costs due to increases in employee compensation, supplies and other supporting external services. RELC also states in its application that its forecast for the test year was to be able to operate at the same level of costs as the current year, despite price escalation generally in the economy.

[23] RELC also noted that there was an increase of 18.5% in salaries from 2020 to 2021 as a full-time apprentice and additional stand-by support were hired. During the hearing, Ms. Bain advised that the apprentice was hired to solve some call-out issues and after-hours emergencies. Ms. Bain also noted that, before she was hired, the technicians did not have days off for the scheduled outages. The addition of the apprentice and stand-by support solved that issue.

[24] RELC has a cost-sharing agreement with the Town of Mahone Bay Electric Utility (TOMBEU) that allows both utilities to benefit from economies of scale in providing services to their ratepayers and maintaining their systems. This agreement has been in place informally since August 2012 and under a written agreement since August 2018, with no expiry date. Staff salaries and stand-by pay are cost shared at 50/50 between the two utilities, and any call-out or overtime is charged 100% to the utility requiring the work.

[25] RELC noted that it shares two resources with TOMBEU: a utility truck purchased by RELC in 2015, and a half-tonne pickup truck owned by RELC. The operating costs of shared resources, such as costs of operation, maintenance and repair, fuel, and insurance, are cost-shared with TOMBEU paying 60% and RELC paying 40% of the costs. RELC highlighted that there have been challenges with inventory and noted that the utilities are working towards a joint inventory.

[26] During the hearing, David Roberts, Board Counsel, asked Ms. Bain for an estimate of actual savings under this sharing agreement. Ms. Bain was unable to provide a number. Further, the Board inquired about the cost allocation of shared employees and shared resources as follows:

> **Q.** …I wanted to -- we touched on the cost-sharing agreement with Mahone Bay. I just wanted to understand if there's been any analysis, since that relationship was formalized, about the actual proportion of work for each utility, in terms of the shared employees and its shared resources.
>
> **A.** (Bain) So your question was; has there been analysis? As far as data, no. Observation on my behalf over two and a half years. And in my opinion, it works out nicely. You know, we might be 60 percent in Riverport this week and 40 percent in the Town of Mahone Bay, whereas next week things change because of a project that we're working on within the town. But we're able to easily service both service areas with very short wait times for work orders and ---
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> [Transcript, February 1, 2023, pp. 153-154]

[27] Ms. Bain also noted during the hearing that RELC is working with the finance team from the Town of Mahone Bay to develop an agreement where the Town manages RELC finances, payables and receivables. Ms. Bain noted that this is a good solution for the staff capacity limit currently experienced by the small administrative team at RELC, as the Town's finance team has more capacity and expertise in those areas. RELC anticipates that by the fiscal year end, the Town of Mahone Bay will be completely executing RELC's finance functions. However, this anticipated agreement and its efficiencies have not been accounted for in the test year.

#### 3.2.1.1 Findings

[28] Generally, the forecasted operating and administrative costs appear reasonable. The Board encourages RELC to continue to identify operational areas of improvement, to develop and to implement solutions that will result in efficiencies in RELC's business processes for the benefit of ratepayers.

### 3.2.2 Purchased Power Costs

[29] In its application, RELC forecast purchased power costs of $1.4 million by applying the rates it expected to pay for electricity in the test year to its forecast of weather-normalized electricity sales to serve its customers, and system losses of 7.67%. In the test year, supply will be purchased from NS Power at a Board-approved rate for municipal utility customers and from a separate wind contract negotiated through AREA. RELC used the best available information on NS Power's rates at the time of the filing. Purchased power is the largest component of RELC's total cost and is forecasted to increase by over 40%, as compared with the current year.

[30] AREA is an inter-municipal agency that procures all power supply for RELC as well as for other Nova Scotia distribution utilities. Considering the serious escalation of fuel prices, AREA sought new arrangements for RELC's wholesale supply of electricity. After evaluating several alternatives, the decision was made to purchase its power supply for 2023 from NS Power at the rate for municipal customers approved by the Board. RELC believes that the supply arrangement with NS Power represents the best alternative available for its customers in terms of both price and security of supply for the test year.

[31] During the hearing, Mr. Roberts questioned Ms. Zarnett about the assumptions that were made for NS Power rates:

> Q. Okay. Now, you again alluded to this in your opening, that your Application assumes that the cost of purchased power will increase by about 40 percent in the test year. And that is 40 percent over the cost of power as of 2022?
>
> A. (Bain) Yes.
>
> Q. Okay. Did you assume, in coming to that 40 percent figure, that Nova -- I should ask the question more broadly. What was your assumption about Nova Scotia Power's rate increase in coming to that 40 percent figure?

A. (Bain) Right. So I think I'd like to allow Ms. Zarnett to speak on this ---

Q. Please.

A. (Bain) --- one, please.

A. (Zarnett) Sure.

The assumption in the material as filed is Nova Scotia Power rates as submitted in their original application, and not any other.

Q. Okay. And then obviously that leads to the Settlement Agreement. I guess we'll hear very shortly as to how that has been handled by the Board, but if the Settlement Agreement is upheld, I presume it will impact on your projection to the cost of purchased power.

A. (Zarnett) It will reduce it but not as significantly as one would hope because in a large measure, the amount of the increase is due to the difference in Nova Scotia Power's rates as compared with the supply that Riverport was able to get previously.

Q. Fair enough. Do you -- have you projected the amount that it will reduce, nonetheless?

A. (Zarnett) Yes. That was -- an initial estimate was included in our rebuttal evidence, so if that's there. But it's small; just let me check it.

(SHORT PAUSE)

MS. ZARNETT: Rather than an average rate increase of 32.5 percent, the Settlement Agreement rates would reduce it to 29.4 percent.

BY MR. ROBERTS:

Q. Thank you. And I take it -- again, could you explain why your -- the amount of the reduction is constrained to basically three points?

A. (Zarnett) Because that's the -- that's the impact of the difference in the two rates of Nova Scotia Power. Riverport also gets supply from a wind contract, which would not have been effective.

Q. Thank you.

[Transcript, February 1, 2023, pp. 33-36]

#### 3.2.2.1 Findings

[32] The Board considers the estimated purchased power costs to be reasonable. Considering the original application was filed before NS Power rates were approved [2023 NSUARB 12], the Board directs RELC to submit, in a compliance filing,

updates for its purchased power costs, revenue requirement and proposed rates based on the approved NS Power rates that were effective on February 2, 2023.

### 3.2.3 Storm Costs

[33] In its original application, RELC added $15,000 to its operating budget as a provision for storm restoration. This was based on RELC's estimation that restoration from a major weather event could result in costs in the $60,000 to $90,000 range, with an average occurrence of every four to six years.

[34] In IRs from Synapse, RELC was asked to provide RELC's budgeted and actual storm costs from the past ten years. RELC answered that current management is unaware whether any provision for storm costs was made in previous budgets. RELC also noted that it has no record of historic storm costs. It further stated that it considers itself fortunate that damage from Hurricane Fiona in its service territory was not as significant as in other parts of the province.

[35] RELC assumed that a significant but not catastrophic storm would impose costs of $90,000 on RELC and occur every 6 years, hence the $15,000 allowance. RELC highlighted that if catastrophic storm damage occurred, RELC would still need to file an application for storm recovery with the Board. Further, if the request is approved, RELC plans to establish a sub-account for these costs or track them offline (in a spreadsheet).

[36] In Exhibit R-14, Synapse's evidence, Ms. Whited stated that the utility's proposal for a storm cost budget allowance was not reasonable at this time because the costs are unsupported by any data. Ms. Whited noted that if the utility is unable to absorb costs associated with storm recovery, it should submit a separate application to the

Board. Synapse's recommendation to the Board was to reject RELC's proposal for a storm cost allowance at this time.

[37] Before the hearing, RELC submitted its opening statement that included the withdrawal of its proposal for a storm cost budget allowance. RELC said it would submit a separate application if it is unable to absorb costs associated with storm recovery.

#### 3.2.3.1 Findings

[38] The Board agrees with RELC's withdrawal of the proposed $15,000 storm cost allowance from the revenue requirement in the test year. The Board directs RELC to remove $15,000 from the revenue requirement and update the revenue requirement and proposed rates in a compliance filing.

[39] The Board views the identification and tracking of storm recovery costs as important evidence to support the reasonableness and justification for any future storm budgets or storm recovery applications. The Board directs RELC to establish a sub-account for storm recovery costs and track them through its existing accounting software, if available, as a preferred method. If this is not possible due to software limitations, RELC should track the information in a spreadsheet.

### 3.2.4 Recovery of Rate Application Costs

[40] In its application, RELC stated that it has included 50% of the estimated costs of this rate application in the operating and administrative expenses. RELC stated that it is likely it will submit a GRA again in 2024. As such, this would result in recovery of half the rate application costs in each of these two years, until 2024. Through IR responses, RELC indicated that it budgeted $57,000 for this application. RELC also

submitted that if this application results in rates in effect for longer than one year, it is appropriate for the costs of the application to be recovered from the customer over a longer period than one year. Further, RELC stated that it intends to bring another general rate application in 2024, but given the time and effort involved in this application, it considers it reasonable to plan that rates would not come into effect for four to six months after its next application is filed.

[41] RELC noted that by only including 50% of the costs, the revenue requirement in the test year is slightly decreased. However, if RELC does not bring a new application in 2024, the budget provision for recovery of regulatory costs would stay in place as part of the rate for an extended period. This concern was raised during the hearing by the Chair:

> Q. Okay. The costs for the application, I think the approach that you've taken is you're proposing to normalize those and expense half of those in the test year and half the next year. Just in terms of the rationale for the two-year period for normalizing those costs, it was tied to the next anticipated rate application? Is that -- am I correct in that?
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> A. (Bain) Yes. Ms. Zarnett?
>
> A. (Zarnett) Sure. That's correct. If they're approved for this test year, then it becomes -- it's part of the expense based in the next year and then there would be an application.
>
> Q. Okay. And what is driving the next application? Is it anticipated capital costs? I guess, really, what I'm wondering is how sure are you it's going to be in two years?
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> A. (Zarnett) I think primarily uncertainty in terms of cost of power, but yes, additional capital also and the costs of the improvements that Ms. Bain is making in operations.
>
> Q. So if there's no -- if there is no general rate application in two years, if we go, again, for another 10 years, which is what we have had in this particular case, then those costs will be carried instead of -- I guess more cost than necessary will be carried if that's the case. Is that correct?
>
> A. (Zarnett) Well, there would be no costs specifically related to applications, but there's already a commitment to take on a number of large projects related to regulatory work and I think that budget would be inadequate to cover those.

Q. Okay. Thank you.

[Transcript, February 2, 2023, Part A, pp. 216-217]

#### 3.2.4.1 Findings

[42] The Board is concerned about the costs of this rate application being included in rates if RELC, despite its good intentions, does not submit a GRA in two years, as expected. This concern is amplified given that this GRA was submitted more than 12 years after the last application was made in 2010. The Board is concerned with carrying costs that are no longer applicable in rates. However, the Board also recognizes the number of various studies and projects that RELC has proposed to undertake for the next GRA and their associated cost that could be expensed through these funds. The Board approves the request to include $28,500 (50% of $57,000) in operating expenses as part of the revenue requirement for the test year.

### 3.2.5 Capital Costs

[43] In its application, RELC noted very little investment has been made in additions or upgrades to its capital assets. Through IR responses, RELC noted that it postponed the government mandated requirement, that came into force in 2008, to eliminate PCBs from all transformers by December 31, 2025. This postponement of needed distribution work also resulted in a supply issue, which now requires the installation of a voltage regulator. RELC stated that the reason for the postponement was to keep rates as low as possible, while continuing to offer safe and reliable service. In 2022, RELC commissioned an engineering review of its distribution system to identify needed capital expenditures over the next several years. RELC noted that all projects identified are required to maintain reliability and safety in its system.

[44] Based on the capital plan developed by the external engineering firm, Strum Engineering Associates Ltd., the total amount added to gross capital for the test year is $354,335. RELC is expecting to invest $105,000 in conductors by the end of March 2023. RELC is also budgeting $78,500 for the purchase and installation of a voltage regulator to address a critical supply constraint on the system. RELC is also including $170,835 in the test year to begin a three-year program to replace transformers containing PCBs, to bring these assets up to accepted safety standards. A further $180,000 of work on bridge poles and line extensions is planned. This amount will be offset by capital contributions. The bridge poles work will not increase the rate base. RELC expects to fund the capital investments in the test year with a loan of $300,000 at a 3% interest rate.

[45] Further, during the hearing, Mr. Roberts questioned Ms. Bain about the postponement of investment:

> Q. (Roberts) I guess related to that is a comment that you make at a couple of places, one in your Application, I believe, in answer to information requests, that you were able to keep the rates as low as possible by essentially postponing investments in infrastructure and that kind of thing. And, again, reflecting back now; do you think it might have been better if investments in infrastructure had been made on a more timely basis, rather than delayed, as they appear to have been?
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> A. (Bain) Absolutely. I think it's fair to say that Riverport Electric has historically underinvested in infrastructure. The funds that we are looking for in the five-year capital plan are to address capacity issues. We've reached -- we're nearing capacity in Kingsburg. So the upgrades proposed and budgeted for are to address capacity concerns.
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> [Transcript, February 1, 2023, pp. 32-33]

### 3.2.5.1 Findings

[46] The Board considers the capital plan to be reasonable, considering the system supply capacity concerns as well as the need to meet the PCB regulations. The Board encourages RELC to review its actual and future capital spending regularly to

identify investments that can be carried out over an extended period to reduce volatility in rates and to maintain its system reliability and safety.

### 3.2.6 Correction for Accounting Treatment of Contributed Capital

[47] In IR-45, RELC was asked to explain a $184,489 difference between the amount used in the Rate Study for 2021/22 total plant of $1,656,808 compared to the total plant amount of $1,841,297 reported on the audited financial statements for year ended March 31, 2022. RELC responded that its auditors restated the financial statements for 2020/21, impacting the results in 2022. RELC noted that as the preparation for the Rate Study initially proceeded based on a prior version of the financial statements, the work needed to be redone shortly before filing. RELC also noted that it is possible, but not certain, that an error was made in reflecting the changes in Exhibit R-1 (Exhibits 1-1 and 1-2). At the time of the IR responses, RELC's consultants noted they would continue to investigate the matter and report the results as soon as available.

[48] During the hearing, Mr. Roberts raised this issue:

> Q. (Roberts) Okay. All right, fair enough. I want to clear up one matter that seems to be unresolved in the IRs. There was a question asked about apparent discrepancy in the value of the assets of the utility, between -- in your filings, different value given in the Application and in the financial statement. And I think the response was, "We're aware of it. We haven't had time to deal with it before the Application." Have you had an opportunity to look at that, and can you explain the discrepancy for the Board?
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> A. (Bain) I'm going to pass that onto Ms. Zarnett, please.
>
> Q. (Roberts) Okay, whomever. Thank you.
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> A. (Zarnett) At the time we began working on the financials for this, it came to our attention that there was an inappropriate treatment of contributed capital in the accounts, I had some discussions with the auditor which resulted in the restated financial statements that were filed, but they were not completed at the time that we did the analysis.
>
> I had made -- knowing it was a problem, I had made an adjustment in order to try and reconcile with prior years and present the Board with -- make sure that the Board had a chance to see this on the basis that was appropriate. But the auditors have now made an adjustment; it's in R-3 for 2022. And my opinion is now that we should go with the number that's in the statements. It was reviewed, I understand, up to the level of partner in the audit firm, so we ought to take those numbers.

> The effect would be probably about $9,000 in net income and about $5,000 in depreciation being added to revenue requirement, which would pretty much offset the removal of the storm allowance, so the revenue requirement that you have is still okay.
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> [Transcript, February 1, 2023, pp. 86-88]

##### 3.2.6.1 Findings

[49] The Board directs RELC, in its compliance filing, to make the changes made to the test year amounts because of the restatement in the financial statements, as well as its impact on revenue requirement and proposed rates.

#### 3.2.7 Working Capital

[50] RELC is requesting approval of a working capital allowance of $193,019. This amount is based on an estimated 36 days' payment lag (10%) applied to its forecast $1,930,190 in net cash expenses (cost of purchased power and operations, maintenance, and administrative costs, but excluding amortization). RELC has not included a further allowance for inventory at this time as it is already requesting a large increase in its working capital compared to the 2010 GRA. Further, RELC is attempting, through cooperation with TOMBEU, to reduce its level of inventory.

[51] The requested amount is nearly four times the working capital of $50,000 in RELC's last GRA. RELC noted that it is not aware of the methodology used in the previous application. It also stated that $50,000 was very conservative at the time and does not provide a reasonable basis of comparison for the working capital requested in this application. RELC did not conduct a lead-lag study for this application. The estimate provided was based on default factors and a practice used by the Ontario Energy Board (OEB). RELC noted that the OEB used 13% of net cash expenses as the default value for some years and this was later reduced in 2016 to about 7.5% when monthly billing for

all customers was mandated. RELC estimated that a mid-point within this range, around 10%, would be reasonable considering RELC has monthly billing for all classes but does not have advanced metering infrastructure (AMI).

[52] During the hearing, Mr. Roberts asked how many days there are between the time a customer receives service and the time the utility receives payment for that service. Mr. Roberts also asked how many days on average there are between when the utility receives power from its suppliers and the time the utility makes the payment for the service received. Ms. Zarnett stated that no data was analyzed for RELC and that the estimate was based on factors that have been used for other utilities by the OEB.

#### 3.2.7.1 Findings

[53] 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. With the utility not conducting its own lead-lag study the Board has some concerns about the reasonableness of RELC's requested working capital amount, but will allow RELC to use 10% of net cash expenses in this proceeding. However, the working capital amount is to be revised based on the changes to the net cash expense arising from this decision.

[54] The Board understands the potential costs involved in a lead-lag study for the utility; however, the Board expects some assessment based on the utility's information to be included in the next GRA. Alternatively, the Board encourages RELC 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.

### 3.2.8 Capital Structure and Rate of Return

[55] RELC asked the Board to approve a return on rate base of 5%. This was based on a deemed capital structure of 60% debt and 40% equity, an estimated cost of debt of 3% and a proposed return on equity of 8%. The request for an explicit return on equity is a departure from the methodology used by the utility in the past. At the hearing, Ms. Bain also confirmed that the utility is not required to pay dividends to an owner and any profits it makes are reinvested. (Transcript, February 2, 2023 – Part A, pp. 208-209).

[56] RELC said the deemed capital structure was consistent with the structure NS Power proposed in its recent GRA and that was found to be reasonable for small distribution utilities elsewhere in Canada. In particular, the OEB uses this deemed capital structure for the distribution utilities it regulates (Exhibit R-12, IR-16). During the hearing it was noted that the utility's actual debt is considerably less than 60% of its capital structure. On cross-examination, Ms. Zarnett said that it was in the interest of customers to have a deemed split so the higher rate of return on equity did not unduly impact the weighted average return on capital.

[57] RELC's estimated cost of debt is based on inquiries it made of a preferred lender about the cost for funding its proposed capital projects. RELC noted that its existing long-term debt bears interest at a rate of 2.7% (Exhibit R-1, p. 14). While RELC observed that the 3% rate for new debt was very conservative under current market conditions, it was selected to reflect discussions with its potential lender earlier in 2022 (Exhibit R-12, IR-17(b)).

[58] RELC's proposed 8% 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 NS Power's current return on equity of 9%, an observation that NS Power's consultant recommended 10.1% in that utility's recent GRA and the formula used by the OEB to determine the return on equity for distribution utilities in that jurisdiction, which in 2022 was 8.66%.

[59] At the hearing, Ms. Zarnett said she considered the 8% return on equity to be "conservative," although she was not surprised by the fact that expert evidence in NS Power's GRA covered a range of possible rates of return as low as 7.5%:

> Q. In light of your lack of surprise over the 7.5 percent figure and your recommendation of eight, why do you say that the recommendation of eight percent is conservative?
>
> A. (Zarnett) I guess with the Ontario benchmark, but also the history of Nova Scotia Power of about nine percent. Other utilities in Canada. And as well, although I don't claim to be an expert in cost of capital, certainly a utility with generation and huge power procurement responsibilities on the open market has a different risk profile than a distribution utility.
>
> Q. If I follow what you're saying correctly, you believe a distribution utility would be lower risk?
>
> A. (Zarnett) Lower risk.
>
> Q. So that would generally translate into a lower return on equity?
>
> A. (Zarnett) That's correct.
>
> Q. And the methodology of the approach to seeking a return on equity in this particular application is very different from the approach that was taken in the last proceeding?
>
> A. (Zarnett) Yes.
>
> [Transcript, February 2, 2023, Part A, pp. 207-208]

[60] In its closing submissions, RELC noted that every public utility is entitled to earn a just and reasonable return under the *PUA*. It submitted RELC's proposed capital structure and return on equity should be approved, emphasizing that any profits realized by RELC would be reinvested in the utility and would, therefore, flow back to the benefit of RELC's customers.

### 3.2.8.1 Findings

[61] 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 *PUA* 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.

[62] 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)]

[63] In the present case, the evidence supporting the utility's request was minimal. In fact, no evidence was presented to the Board by experts qualified to provide an opinion on RELC's cost of capital. Instead, the requested return on equity was benchmarked against NS Power's return on equity and what the OEB allows distribution utilities to recover in that jurisdiction.

[64] While the Board appreciates that the cost of a cost of capital study comparable to what was before the Board in *NS Power 2023-2024 Rate Application* would be quite significant for a small utility such as RELC, the evidence provided in this

proceeding does not provide the Board with the information needed to satisfactorily assess a fair return. The risk profile of a municipal distribution utility with very little debt may be materially different than that of NS Power and many of the utilities covered by the OEB's generic, formula-based return on equity for distribution utilities.

[65] That said, given the utility's request for a specific rate of return in this proceeding and its underlying entitlement to do so in s. 45 of the *PUA*, the Board struggled through the limited evidence provided to determine a suitable rate of return in the circumstances. In this case, the Board finds that a rate of return on equity of 7.5% is appropriate. While this is below the requested rate, it is the bottom of the range of the rates advanced by experts in NS Power's recent GRA. Furthermore, while recognizing that she is not a cost of capital expert, the rate is consistent with Ms. Zarnett's belief that a distribution utility would require a lower return on equity than a utility with generation and huge power procurement responsibilities on the open market (Transcript, February 2, 2023, Part A, pp. 207-208). As such, and in the absence of stronger evidence, the Board considers the lower end of the range of returns advanced by experts in NS Power's recent GRA to be reasonable.

[66] If RELC feels a higher rate of return is warranted, it should provide the Board with better evidence in its next GRA. It is possible that this could also be considered in a generic proceeding involving some or all the municipal electric utilities in Nova Scotia. Such a process could be a reasonable and cost-effective way of determining an appropriate rate of return for these very small utilities in their future rate applications. This is similar to the approach that would have been taken by the OEB to set a default return on equity for distribution utilities. It would allow the Board to consider

and weigh specific evidence about the risk and circumstances of municipal electric utilities in Nova Scotia and to consider how the general principles taken into account when setting a rate of return on equity might apply to them.

### 3.3 Cost of Service

[67] RELC's cost-of-service assessment was based upon the cost-of-service principles and practices that it applied in its last GRA. As a utility with no generation capabilities, its costs generally relate to purchase and distribution of power functions. Its functionalized costs are then classified as demand, energy or customer-related; and, finally, they are allocated to rate classes.

#### 3.3.1 Minimum System vs. Basic Customer Methodologies

[68] The Board's consultant, Synapse, challenged the approach used by RELC to classify distribution system costs. Synapse described this approach as based on the minimum system method. In Synapse's words, 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….The costs associated with conductors, spur lines, poles and fixtures, and transformers 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.
>
> [Exhibit R-14, pp. 6-7]

[69] Synapse described RELC's classification of 30% of the costs for conductors, spur lines, poles and fixtures, and transformers as customer-related, as indicative of the minimum system which estimates "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 R-14, p. 6)

[70] In contrast, Synapse suggested using the basic customer method. Under this approach, only the meter, service drop and the billing and collection costs are classified as customer-related as these are the "costs that increase or decrease with the number of customers on the system" (Exhibit R-14, p. 9). While RELC classified distribution costs (such as conductors, spurs, etc.) as 30% customer-related and 70% demand-related; Synapse would classify them as 100% demand-related. The result is that an additional 2.6% of costs would be customer-related, and a substantial difference in the amount of the customer charge, which is discussed further in s. 3.4.2 in this decision.

[71] In response, the RELC's consultants asserted that there were analytical challenges with such methods that related to data acquisition, the cost of studies and the reasonableness of results. Therefore, it chose to continue with the existing classification factors RELC used in its 2010 Rate Study. It elaborated that:

> ...The minimum system method has a long history of use in Nova Scotia for both NSPI as the major utility in the province, and also for the municipal utilities. This approach is also widely used in other Canadian jurisdictions, for small distribution-only utilities as well as for larger and integrated utilities. RELC was not previously directed by the Board to review alternative methodologies and submit findings, and has not done so. It would be inappropriate for it to be changed for RELC in this proceeding.
>
> [Exhibit R-16, pp. 3-4]

### 3.3.2 Transformer Classification

[72] In Exhibit R-1 (Exhibit 4-2 and Exhibit 4-3), RELC classified transformer costs as 30% customer-related and 70% as demand-related, even though in RELC's previous study transformers were treated as 100% demand-related. RELC explained that "the number of transformers would be affected by the number of customers and the distance between them" and that "[f]or consistency with other distribution assets, and

because the alternative under consideration was 0% customer related, BDR considered it reasonable to apply a 30% customer factor to these assets." (Exhibit R-13, p.12)

[73] In its final argument, RELC agreed that, if the Board wants consistency between NS Power and the smaller municipal electric utilities, transformers can be classified 100% to demand.

### 3.3.3 Correction to Classification Errors

[74] In its rebuttal evidence (Exhibit R-16, pp. 7-8), RELC noted that meters were inadvertently left out from the ratios used in Exhibit R-1 (Exhibit 4-2 and Exhibit 4-3), causing very small errors in the revenue-to-cost ratios. Corrections were provided.

### 3.3.4 Cost of Service Findings

[75] As discussed in s. 3.6 in this decision, the Board is concerned with the limited data and analysis that is specific to RELC. There has not been a detailed evaluation of RELC's cost-of-service methodology. 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 RELC in this proceeding, except that transformers should be 100% demand-related, as was the case in RELC's past applications. The Board anticipates that this issue may be one that is more thoroughly considered when NS Power completes its next cost-of-service study, which is expected no later than December 31, 2025.

## 3.4 Rates and Charges

### 3.4.1 Domestic Customers Served at More Than 200 Amps

[76] In its last GRA in 2010, RELC was concerned that the energy used by some larger residential customers may increase the overall demand charge it would be billed by NS Power without an offsetting revenue increase. To counter this, the utility proposed to restrict the Domestic Service rate availability to customers who took service at 200 amps or less. At RELC's request, the Board approved an amendment to RELC's Domestic Service tariff under the Schedule of Rates for Electric Supply and Service, so only customers with a service of 200 amps or less would be eligible for the Domestic Service rate. Customers with service over 400 amps would be billed at the General Service rate. The Board directed RELC to study the impact of the higher service customers on demand and to track any customer feedback on the new approach.

[77] RELC frankly admitted that it did not implement the changes to the Domestic Service rate that it had requested in 2010. It still did not do so after an admonishment from the Board in a May 2, 2013, decision letter in response to a billing complaint. In that matter, the Board noted that RELC had unilaterally decided to charge 400-amp customers the Domestic Service rate, in violation of the Board's order and the *PUA*.

[78] Ms. Bain expressed contrition for this lapse, which took place under the utility's previous administration. She could not explain why RELC had not returned to the Board to revert to the previous regulation and formally allow the Domestic Service rate to apply to 400-amp customers.

[79] The Board received a letter of comment from a 400-amp RELC customer. The customer expressed concern about the potential change in practice and

the impact on his rates if he were treated as a member of the Small General Service class. The customer's view is that 400-amp customers should be charged the Domestic Service rate.

[80] RELC indicated that, in preparing the Rate Study, it considered customers with service above 200 amps as Domestic Service customers for the purpose of its analysis. RELC could not point to any information from customers or other utilities that could help inform an approach to an alternate billing structure for 400-amp residential customers. Ms. Bain indicated her belief that RELC may be the only utility whose rules limit Domestic Service to 200 amps and lower. Ms. Zarnett confirmed that she did not know of any other utility rate schedule where "any single-family home was not treated as a Domestic customer":

> A. (Zarnett) So I guess I would say, first of all, that I've never -- I've never seen a utility rate schedule where any single-family home was not treated as a Domestic customer. There's lots of variations in who else might be included, but a single-family home equals Domestic, pretty much everywhere. And the other thing is, as you and Ms. Bain just discussed, there isn't any data to substantiate that those customers are more winter-intensive or more -- have a worse load factor than any other Domestic customer, even though presumably their total consumptions are larger. So the answer is we don't know. If we could look at the revenue-to-cost ratios under the Domestic rate of those customers alone, we don't know what we would get.
>
> [Transcript, February 1, 2023, pp. 164-165]

#### 3.4.1.1 Findings

[81] The issue of RELC's treatment of residential customers with service above 200 amps has been unsettled for some time. The Board has already expressed its concern that the utility was not billing customers in accordance with its approved Schedule of Rates and Charges. The panel was encouraged by the utility's stated commitment to implement additional controls and good governance practices to ensure it complies with its regulatory obligations going forward.

[82] The Board agrees with the utility's revised position that the 200 amp or less restriction should be removed from the tariff for Domestic service. This will align with the expectation of 400-amp customers based on RELC's past practice and with the Domestic Service tariffs of other utilities.

[83] In preparing the Rate Study, domestic customers with service above 200 amps were considered Domestic for the purpose of the analysis. No updates to the Rate Study as originally filed are required to address this change. The Board approves the removal of the restriction on Domestic Service to customers with 200 amp or less service. The Board directs RELC to file its updated Domestic Service tariff in its compliance filing. The Board also encourages RELC, where possible, to track the impact of larger service customers on its system, to better inform its future rate-making approach.

### 3.4.2 Customer Service Charges

[84] In its application, RELC proposed that all customer service charges should be increased proportionately with the overall increases in rates.

[85] Ms. Whited recommended that the Domestic class service charge be maintained at its current level given her calculations for customer-related costs under the basic customer method. BDR did not agree. They argued that the proposed approach is consistent with NS Power's GRA proposal and the charges of other small utilities. The proportional increase in charges was generally consistent with RELC's approach to other rate components. Ms. Zarnett explained that every customer in the class would bear the increase *pro rata* with its prior bill. It wouldn't have a different impact on a smaller consumer than a larger consuming customer.

[86] The current service charge for Domestic Service is $12.25/month. By Ms. Whited's calculation, even using the minimum system method proposed by RELC and accepted by the Board earlier in this decision, the estimate for the Domestic class service charge should be $14, rather than $16.60 as RELC proposed.

[87] In Undertaking U-6, Synapse provided calculations for the service charges. Ms. Zarnett also provided calculations (Undertaking U-3), which differ slightly from what Ms. Whited provided in response to Undertaking U-6. In its closing submissions, RELC agreed that the customer charges can be based on the cost-of-service calculations as calculated in Undertaking U-3. RELC agreed that Ms. Whited's calculations correctly treated: amortization of customer-related distribution assets; amortization of metering and billing related assets; operations and maintenance expense on customer-related distribution assets and metering and billing expenses. However, RELC disagreed with Ms. Whited's treatment of the customer-related portion of administrative and general costs and her exclusion of the customer-related component of financial costs.

[88] Using the cost-of-service study as filed, RELC calculated (Undertaking U-3) that, based on costs classified as "customer related" and allocated to the Domestic class, the service charge would be $16.93.

#### 3.4.2.1 Findings

[89] The Board finds it reasonable for the customer charges to be updated to reflect the cost-of-service. In addition to representing customer-related costs more accurately, this will help avoid cross-subsidization across customer classes. While there are questions about the current cost-of-service study, RELC's calculation in Undertaking

U-3 more closely reflects the evidence before the Board than the proportional increases. The Board approves the customer charge changes, based on the methodology used in Undertaking U-3 for the "Transformer 100% Demand" approach. This will apply to the service charge for the Domestic Service class. The Board directs the utility to confirm the final charge in the compliance filing, applying all the revisions directed by the Board in this decision.

### 3.4.3 Declining Block Rate Structure

[90] RELC has long employed a declining block rate structure for Domestic Service, Small General Service, General Service and Large General Service. In response to Synapse IR-4, RELC addressed the cost basis for declining block rates, as follows:

> In a declining block rate structure fixed and variable non fuel costs are intended to be recovered both through the service charge and through differential between the 1st block energy charges and the balance block charges. It is intended that all such costs are recovered when each customer "fills" the 1st block, and then the second block recovers demand and energy related only.
>
> RELC has not carried out a study to review the relationship between the allocated fixed "customer related" costs of its classes and the costs recovered through the service charge and block price differentials.
>
> [Exhibit R-13, p. 5]

[91] At the hearing, Ms. Zarnett elaborated that declining block rates were more widely used in the past by water and electric utilities. The block rates offered some protection to smaller customers against the fixed component of a bill. They allowed the utility to bill for a smaller fixed component and then collect the shortfall from the differential between low and higher use (billed at the higher rate). Ms. Whited's report indicated that many jurisdictions moved away from declining block rates, particularly for residential customers, because they are difficult to justify from a cost-of-service perspective. Ms.

Whited recommended the Board direct the utility to file a proposal to eliminate the declining block rate structure, unless the rate structure can be supported by evidence that demonstrates it is cost-effective.

[92] The utility stated that its declining block rate is likely not supported on a cost-of-service basis. Given the urgency to complete this application, RELC did not undertake a study or propose any changes to the declining block structure under this application. RELC said it was not averse to considering a rate redesign to employ a single customer charge in a future process. However, the utility preferred an opportunity to determine the impact of removing the second block on lower-use customers, who may end up with disproportionate increases.

#### 3.4.3.1 Findings

[93] The Board understands RELC's concerns about the impact of high rate increases on customers. However, the utility operates on a cost-of-service model, as set out in the *PUA*. This prescribes the way the Board must assess the application. RELC's rates and charges should be the same for substantially similar circumstances and conditions of service. If the rates do not accurately reflect the cost associated with serving additional load, lower-usage customers may end up subsidizing higher-usage customers. Lower prices for higher levels of electricity consumption also reduces an incentive for energy efficiency and conservation.

[94] The parties agreed that the current declining block rate structure does not appear to be based on cost-of-service principles. RELC has not provided any cost-of-service analysis that supports retaining the declining block. Nevertheless, given the lack of contrary evidence, the Board sees value in a more detailed review of the impact

of removing the second block and any alternate proposals, prior to recommending its elimination.

[95] The Board directs the utility to review whether maintaining the second block rate can be justified from a cost perspective, and return to the Board with the results of its analysis in its next GRA.

### 3.4.4 New Cable Rate Class

[96] RELC currently bills electric service for cablevision under its Small General Rate Class. However, RELC considered the cost of serving this demand separately in its cost allocation study. The results suggested that the rates paid by cable units were over-recovering the cost to serve them by a large margin. As a result, RELC proposed no rate increase for these units in this proceeding, even though it did propose an increase for its Small General Rate class.

[97] In Board IR-39, RELC was asked about this:

> **Request IR-39**
>
> On page 19 of the Rate Study, Riverport notes that the cablevision requirements are billed under the Small General Rate, but they appear to be considered separately in the cost allocation study, the revenue-to-cost ratio assessment in Exhibits 5 and 6, and the revenue reconciliation in Exhibit 7. Please explain.
>
> **Response to Request IR-39:**
>
> It is typical for small unmetered loads to be considered separately from metered customers for purposes of a cost allocation study. These customers are distinctive in terms of cost causation because a cable power supply has 100% load factor on a consistent basis, the same load every month. They do not require certain services needed by metered customers, including meters, meter reading, telephone support, etc. They are typically all billed at once, with the bill going to one main account.
>
> As a result, even if their bills are determined at the same rate, these customers can be expected to have a very different revenue/cost ratio than a typical metered customer.
>
> [Exhibit R-12, pp. 60-61]

[98] RELC had not explicitly requested the creation of a new rate class in its application for cable power supply but was asked about this by the Board at the hearing:

> Q. … Is the utility proposing essentially a new rate class for cable?
>
> A. (Bain) We had discussed that, yes.
>
> Q. The ---
>
> A. (Bain) I'm trying to remember what we had -- I might defer that to Ms. Zarnett, but I know that Mr. Dominie had suggested that.
>
> Q. Yeah. I think there's going to be a different rate for it now because you've held that constant while you've increased the small general.
>
> So Ms. Zarnett, do you want to jump in here?
>
> A. (Zarnett) Yes. I would recommend that there be a separate rate for them. I'm familiar with those cables power supplies, having done a fair amount of work for Rogers. They are -- they're a fixed load. They consume the same amount all the time. It's 100 percent load factor, which makes it very different from a small general service customer.
>
> The billing -- they have no meters. The billing costs are different. They're different in every respect in terms of cost causation. They should have their own rate.
>
> Q. I'm not sure who to ask this to, but is it possible to get some proposed tariff language for the rate class by way of an undertaking?
>
> A. (Bain) Absolutely. I'll manage that.
>
> [Transcript, February 2, 2023, Part A, pp. 211-212]

[99] RELC's response to Undertaking U-4 provided draft language for the proposed tariff (Exhibit R-18). As proposed, the new rate would have both a monthly service charge and a per kilowatt hour energy charge; however, the specific rates were left blank in the response to the undertaking. The tariff notes that it is available to cable TV power packs where consumption is unmetered. The application of a per kilowatt hour energy charge to an unmetered demand poses some difficulties, but the tariff contemplates that the utility and the customer will agree upon the level of consumption for billing purposes based on documentation about the electricity consumption of the unmetered load or, at the option of the utility, periodic monitoring of actual consumption.

#### 3.4.4.1 Findings

[100] The Board is prepared to approve the design of this rate but needs to approve the specific service charge and energy charge in this proceeding. The Board directs RELC to provide the service charge and energy charge for the new cable TV power pack rate class along with the calculations used to derive the forecasted revenue from this rate class based upon the revenue-to-cost adjustments discussed later in this decision and the forecasted annual energy requirement of 61,320 kilowatt hours (Exhibit R-1, p. 12).

### 3.4.5 Revenue-to-Cost Ratios

[101] Exhibit R-6 (Exhibits 5 and 6) set out calculations showing a revenue shortfall in 2023 of $469,806, and that an overall average rate increase of 32.5% was necessary to satisfy RELC's proposed revenue requirement. In the rebuttal evidence filed by BDR NorthAmerica Inc., it was noted that a preliminary analysis of the impact of lower than assumed rates under NS Power's municipal tariff would reduce the overall average rate increase by approximately 3%.

[102] Even with the substantial deficiency under existing rates, RELC observed that the revenue-to-cost ratio for the combined General Service and Large General Service classes was close to parity, as was the revenue-to-cost ratio for Street Lighting. The revenue-to-cost ratios for the Domestic and Small General Service classes were substantially under-recovering, while the Yard Lighting and Cable Unmetered revenue-to-cost ratios showed substantial over-recoveries.

[103] To address the shortfall in revenue under current rates, RELC proposed to apply a uniform rate increase to all metered rate classes while maintaining Street

Lighting and Cable at existing rates and reducing Yard Lighting rates by 17.1%. The proposal continued to show a substantial over-recovery for Yard Lighting and Cable. Additionally, the proposal results in the combined General Service and Large General Service classes substantially over-recovering their fully allocated costs under the proposed rates.

[104] Ms. Whited considered the proposed rate increases were not consistent with the results of RELC's cost-of-service study and would result in several rate classes remaining well outside a revenue-to-cost band of 95% to 105%, or even outside a band of 90% to 110%. To address this, Ms. Whited proposed a three-step process to develop alternative rate increases. The first step involved reducing the revenue-to-cost ratios by half for rate classes whose ratio exceeded 120%. The second step was to uniformly increase the rates for all other rate classes up to a revenue-to-cost ratio cap of 110%. The final step involved allocating the remaining rate increase to any class that had not yet reached the revenue-to-cost ratio cap of 110%.

[105] In her evidence, Ms. Whited applied this methodology to RELC's cost-of-service results based on her recommendation that the Board require RELC to use the basic customer methodology for allocating distribution system costs (which the Board has not accepted in this proceeding for the reasons considered earlier in this decision). In response to Information Request IR-3 from RELC (Exhibit R-15), Ms. Whited was asked to apply her 3-step process based on the revenue-to-cost ratios using the minimum system method followed in the Rate Study. The results showed required rate increases of 37.2% for the Domestic and Small General Service classes, 9.3% for the combined

General Service and Large General Service classes, and 11% for Street Lighting. Reductions were shown for Yard Lighting (-17.9%) and Cable (-15.4%).

[106] In its closing submissions, RELC recognized that the revenue-to-cost ratios under its proposed rates were outside of the 95% to 105% band generally used by this Board, but the utility maintained its position that the rate increases should be assigned to its rate classes based on its proposal in the Rate Study. RELC's consultants did not have a high degree of confidence in the results of the Rate Study given the data limitations, especially the data necessary to determine class coincident and non-coincident peak responsibility of each customer class and resulting uncertainty about the demand cost allocators. Given this uncertainty, the potential for inconsistent adjustments once better load research data is available, and the impact that adjustments would have on Domestic Service and Small General Service classes at this time, RELC was reluctant to narrow the revenue-to-cost ratio range for rate class outliers.

[107] At the hearing, Ms. Whited explained that her concern with the approach proposed by RELC was that it ignored the cost-of-service study entirely. She viewed this as essentially saying that the 2010 cost-of-service study was superior to the more recent one, although she acknowledged that the 2022 study basically just updated some allocations from the previous study.

[108] In response to a question from the Board, she addressed the uncertainty in the recent Rate Study:

> Q. Okay. And you may have answered this already in your response to Mr. Fisher's questions. But in terms of the position that I understand the utility's consultants to be taking around the adjustment to the revenue-cost ratios for the rates that are proposed in this proceeding, I kind of get the sense that it's more the pursuit of precision without accuracy type of thing, that the input data is, for lack of better words, so unreliable that the degree of precision that would come with adjusting the revenue-cost ratios as you propose perhaps should wait until there's better data.

> Do you feel that is appropriate and, if not, you know, I guess why in the face of, I guess, really, a data issue do you feel that making those adjustments are necessary now?
>
> A. It's a difficult position to be in given the data quality. However, if we adjust all of the rates equally, then we're basically saying that the 2010 study is superior to the 2022 study. And although I recognize that the 2022 study's allocation factors are imperfect, there was effort made to make some reasonable adjustments to them and it's my perspective that, while imperfect, those adjustments are likely superior than the 2010 – what came out of the 2010 study.
>
> So for that reason, I propose some adjustments to the revenue-to-cost ratio within a larger band than I might otherwise propose.
>
> [Transcript, February 2, 2023, Part B, pp. 275-277]

[109] Ms. Whited also acknowledged that there may be concerns about introducing volatility if adjustments are made now and better data later shows that different adjustments should have been made; however, she noted that there was significant volatility due to other factors such as fuel prices and said she expected that volatility arising from the proposed adjustments would be smaller.

### 3.4.5.1 Findings

[110] The Board appreciates that there are data limitations with the Rate Study submitted by RELC in this proceeding. Unfortunately, the utility did not have the information it should have to provide the Board with data upon which it could conclude that its proposed rates were fair as between the utility's various rate classes. The Board also concludes that, given the attention paid to the Rate Study by RELC's consultants, and their exercise of judgment to develop cost allocations they viewed as the most reasonable assumptions to be made at this time, the cost-of-service study filed in this proceeding is the best available evidence before it when considering whether the utility's costs have been allocated fairly amongst its customers. Based on that study, it appears that there are some rate classes that are overpaying. The Board is particularly concerned

that the utility's General Service and Large General Service rate classes appear to be subsidizing its Domestic Service customers.

[111] The Board understands the utility's reluctance to address this issue given the large rate increases it is proposing in this proceeding. As the Board noted in its recent decision on NS Power's GRA, it is keenly aware that any rate increase has an impact on ratepayers, particularly low-income customers and those on a fixed income.

[112] In *NS Power 2023-2024 Rate Application*, the Board referred to the Nova Scotia Supreme Court, Appeal Division, decision in *Nova Scotia (Public Utilities Board) v. Nova Scotia Power Corporation*, (1976) 18 N.S.R. (2d) 692, which noted the "…'justness' of rates has two aspects – rates of a utility as a whole must be 'reasonable' and just for the public it serves and just and 'sufficient' for the utility itself – and the rates for the various customers or classes of customer of a utility must not as between each other be 'unjustly discriminatory' or 'preferential'" (para. 20).

[113] The Board recognizes that the allocation of costs in a cost-of-service study is not an exact science. That is the reason why the Board strives to keep revenue-to-cost ratios within a range as opposed to requiring them to be set precisely at 100%. However, the revenue-to-cost ratios are simply too unbalanced in this case and must be addressed. The Board, therefore, directs the utility to determine its rates following the three-step process proposed by Ms. Whited, and present them in a compliance filing. Even with that methodology, there are rate classes whose revenue-to-cost ratios are still outside of a reasonable range, but there is a need to balance adjustments with some gradualism. The Board expects the utility to address this, however, in its next rate application.

### 3.4.6 Distribution Losses

[114] In its last GRA in 2010, RELC reported system losses of between 7.5% - 8.8% over the previous three years. At that time, RELC was directed to undertake a system-loss study and recalculate its time-of-use rates using actual losses. Ms. Bain explained past challenges in the administration and management of the utility. She highlighted the difficulty in conducting studies with limited resources. In its opening statement and in response to questions from Board Counsel, RELC confirmed its commitment to undertake a system-loss study later this year:

> …Going forward, RELC is committed to remaining more vigilant in ensuring compliance with all Board directives and legislative requirements, including the outstanding directives to perform a system-loss study and recalculate the time-of-use rate using actual losses, which will be done later in the year.
>
> [Transcript, February 1, 2023, pp. 28-29]
>
> …
>
> A. (Bain) So as far as decisions, that would be a decision of the Board, of my Board, and I have -- I have not brought the final quote to them for approval at this point, no. I don't anticipate there will be any issue. The Board is fully aware that we have committed to performing a system-loss study in 2023.
>
> Q. And when do you think you'll be able to bring a proposal to the Board?
>
> A. (Bain) Within 30 days.
>
> [Transcript, February 1, 2023, p. 68]

[115] Mr. Regan explained that RELC's estimated system-loss percentage is essentially an energy-in, energy-out calculation, comparing the energy purchased to energy sold. The calculation can be complicated by various factors such as lags in service meter reads.

[116] Mr. Winstone discussed how RELC arrived at its system-loss percentage for the purpose of its time-of-use rates calculations. He used 7.6% as RELC's average system loss. The number was calculated starting with monthly data for each

month starting January 2021 and ending August 2022. Mr. Winstone calculated the difference between the inputs to the system (energy purchased) and sales over those eight, 12-month periods, and took the average. This system-loss estimate is fairly consistent with RELC's past application. The utility said further work and data was required to refine the class-level loss estimates. That data was not readily available at the time RELC prepared its application.

[117] RELC recognized that it had not provided an analysis of system losses, as directed in the 2010 GRA order. The utility committed to completing a system-loss study in 2023 to comply with that order. Ms. Bain indicated that RELC could cover the associated costs of the study in its 2023 budget.

#### 3.4.6.1 Findings

[118] RELC's estimated system losses were high in 2010. They remain high. In the absence of better data, the Board accepts the methodology used to estimate system losses based on the average difference between the amount of energy purchased and energy sold eight months prior to the application. The Board looks forward to a review of RELC's planned system-loss study at its next GRA, along with RELC's response to the study results.

### 3.4.7 Phasing-in the Rate Increase

[119] As noted earlier in this decision, RELC's application proposed a 32.5% overall average rate increase. As proposed in the utility's application, the rates for its Domestic, Small General, General Service and Large General Service classes would increase by 34.3%. The impact of the proposed rates in the original application on the average monthly bill for a Domestic Service customer is approximately $43 ($516 per

year) (Exhibit R-12, IR-4). Customers who use more energy than average (e.g., electric heat customers) would see higher increases while those customers using less energy than the average would see smaller increases.

[120] RELC's application noted it was very conscious of the hardship that an increase of this magnitude may impose on its customers and anticipated the Board would share this concern. It noted that it was exploring mechanisms for rate mitigation and funding to support that.

[121] In its opening statement at the hearing, RELC addressed this issue:

> With respect to the rates requested in the Application, RELC appreciates that the magnitude of the increase is significant for its customers. As noted in the Application and in its responses to Information Requests, RELC has continued to consider ways to mitigate the impact on its customers. The recent Settlement Agreement in NS Power's General Rate Application that occurred following the passage of Bill 212, if approved, will reduce the costs of power purchased from NS Power as compared to what was assumed in the Application, and RELC expects that it will be in a position to adjust the requested rates to take this into account as part of the Compliance Filing in this proceeding. This will have a downward impact on the requested increases as compared to the Application as filed. Deferrals of the remaining increases would all attract additional financing costs that would eventually need to be borne by customers, so while RELC is not opposed to further rate mitigation in principle, it does not have any specific proposal to offer at this time.
>
> [Exhibit R-17, p. 2]

[122] This was explored further in questions from the Board panel at the hearing:

> Q. Ms. Bain, the increase that's being requested, approximately 30 percent, that's a significant increase.
>
> A. (Bain) Yes, it is.
>
> Q. And with an increase of that size, you naturally think about is there a way to mitigate or phase in or whatever. I know the utility had looked at that, but yet, you know, ultimately, in your opening statement, you say you're not coming forward with a proposal.
>
> Why are you not bringing forward a proposal of any sort to manage that?
>
> A. (Bain) I think that we were waiting for the Board decision and how you would rule in that regard.
>
> Interesting for the Riverport Electric is that financing for smoothing is ultimately approved by the electors.

Q. So what happens if the Board decides that it's going to be phased in over three years?

A. (Bain) Then we approach electors with another special meeting. We'll have done our math. We'll know the -- how much we need to borrow and we ask for elector approval to borrow those funds.

Q. And what if they don't approve?

A. (Bain) That is possible, but unlikely.

Q. So do you have any sense of if the Board were to consider a phase-in what might be feasible for the utility? Like would it be two years, three years?

A. (Bain) When I had worked some preliminary math, I had looked at three years.

Q. And is there a concern -- I know the utility had indicated it's coming back for a rate increase probably in 18 months at a minimum, maybe a little bit longer, that if we defer some of that it will compound that increase in the future that you'd be looking for?

A. (Bain) Yes, that's correct.

Q. Did you kind of think about that when you were looking at what possibly be able to manage - - be managed by the utility in the sense of if you were looking at phasing it over three years, you still felt even with what you were seeing coming down the road in terms of future increases that could still potentially be managed?

A. (Bain) Yes.

Q. I guess ultimately, really, what I'm wondering about is if the Board does decide that it should be phased in over three years, it's not automatically going to be driving the utility into financial peril by doing that? It is manageable?

A. (Bain) Yes, it is manageable.

Q. And I understand that if we were to go down that path, you'd be looking for a deferral mechanism to deal with the shortfall in your costs between the -- well, through the phase-in period. In terms of the financing costs for that, am I correct that you were contemplating that it would just be the interest rate from the bank that you would be charged or would you be charging also sort of your full weighted average cost of capital on that?

A. (Bain) I'm going to let Ms. Zarnett answer that question.

A. (Zarnett) I think what we had discussed was that in the interests of the customer, it should be the lower rate.

[Transcript, February 2, 2023, Part A, pp. 176-180]

[123] RELC revisited the issue again in its final argument:

During the hearing, RELC was questioned about potential options to mitigate the magnitude of the rate increase. In response to questions from Board Counsel, Ms. Bain noted that the Commissioners have agreed in principle to rate mitigation, but exploration of potential financing options remains in progress. RELC's primary concern, as Ms. Bain confirmed in response to questions from the Chair, is that RELC is likely to come back for a rate increase in 18-24 months, and that deferral of costs today will only compound the increase that would be sought in the future. In addition, RELC notes the following comment from the Board's recent decision with respect to the NS Power's General Rate Application, which states at para. 8 and is equally applicable here:

> Further, consistent with principles of utility rate regulation recognized by the Supreme Court of Canada, the Board cannot simply disallow NS Power's reasonable costs to make rates more affordable. These principles ensure fair rates and the financial health of a utility so it can continue to invest in the system providing services to its customers. While the Board can (and has) disallowed costs found to be imprudent or unreasonable, absent such a finding, NS Power's costs must be reflected in the rates paid by customers. **Regulatory tools, such as deferrals, are available to the Board to mitigate the impact of rate increases, but there are trade-offs involved with using these tools as they often result in higher costs in the longer term."** [emphasis added in original]

Although there was some discussion of a potential three year rate smoothing during the hearing, RELC is opposed to a deferral over that long a period of time, given that the deferred costs will accrue interest at RELC's cost of debt and the next General Rate Application is expected in the 18-24 month timeframe. If the Board concludes that some form of rate mitigation is required, RELC recommends that the Board order a deferral over a two year period. Under this type of approach, the overall rate increase in 2023 could be capped in the range of 15%, with the remaining costs sufficient to recover the 2023 approved revenue requirement (including interest carrying costs) to be approved for rates starting January 1, 2024. RELC submits that the tradeoffs involved in a deferral period any longer than two years would not be in the best interests of the utility or its customers.

[RELC Final Argument, pp. 3-4]

#### 3.4.7.1 Findings

[124] Given the magnitude of the increase, and to mitigate rate shock to customers, the Board finds it is appropriate to phase-in the proposed rate increases. The Board accepts RELC's submissions that the trade-offs involved in such a deferral for a period any longer than two years would not be in the best interests of the utility and its customers.

[125] Additionally, the Board finds that it would be more appropriate to reflect more of the increase in the first year to reduce interest costs associated with the deferral, due to the utility's belief that it will need to apply for an additional increase within 18 to 24 months, and given the likelihood that under-recovered fuel costs will be added to RELC's purchased power cost through NS Power's fuel adjustment mechanism. As such, the

Board directs a two-year phase-in of the rate increase, with the rate increase in 2023 capped at 20% for each rate class and increasing to the full approved increase beginning January 1, 2024.

[126] While this will only modestly mitigate the increase for some rate classes and only for a short time, the Board is very concerned about pushing unrecovered costs into a future period when they may only compound future rate increases that could also be significant. Unfortunately, the evidence presented by the utility in this case did not provide comfort that its rates would remain stable and not increase for a period that would allow a more extended phasing-in of this significant rate increase. As a result, even the temporary deferral leaves a very large increase.

[127] The difference between the rate cap in the first year, and the full rate approved in this decision, is to be deferred for later recovery by RELC, with interest. The Board directs the utility to track the deferred revenue in 2023 by rate class and to apply to the Board in 2024 for approval to begin recovering the deferral beginning January 1, 2025. If RELC files a GRA before that time, the recovery of this deferral may be included as an issue to be determined in that proceeding.

[128] Finally, the Board must also be mindful that the ability of a very small utility such as RELC to defer the recovery of revenue will be limited by its financial circumstances and its ability to finance the deferral. RELC has advised that it believes it can manage a phasing-in of the increase in the timeframe set by the Board in this decision. However, if the utility finds that it becomes impossible to manage the deferral, it should immediately apply to the Board for relief.

### 3.4.8 Pole Attachment Charge

[129] RELC requested approval of an increase in the rate it charges to telecommunications carriers to attach their equipment to poles owned by RELC (pole attachment charge). The proposed increase for a charge of $22 amounts to an increase of $7.85 or nearly 55%.

[130] For years, RELC maintained a pole attachment charge of $14.15, the same rate in NS Power's Regulations dated January 1, 2019. RELC explained that it aligned its proposal for the fee increase with the pole attachment fee negotiated in the settlement agreement proposed between NS Power and communications companies in *NS Power 2023-2024 Rate Application*, for the rate of $22.00 per year with annual cost escalations of 2%.

[131] RELC did not carry out a Pole Attachment Fee Study. It indicated in its response to Board IR-61:

> Riverport has not carried out a Pole Attachment Fee Study. Riverport submits that its internal staff do not have the resources to collect the internal data in support of such a study while resources are stretched to meet the requirements of the current GRA. Riverport also submits that the cost of consulting expertise for the Study would be an unreasonable burden on its customers at this time of major escalations in cost of purchased power and capital needs.
>
> [Exhibit R-12, PDF p. 91]

[132] Instead, RELC asked its consultants, BDR, to review the results of pole attachment studies carried out by other utilities. BDR reviewed approved charges for utilities in Ontario, New Brunswick, and looked at NS Power's most recent proposal in its GRA in 2022. BDR noted that NS Power's initial proposal included a pole attachment fee of $37.71, based on a fee study. BDR's fee study review showed that studies had supported fees between $37 and $53 for other Canadian utilities. BDR believes that a study for RELC would likely support pole attachment fees higher than $22 per year. RELC

attempted to balance reasonable compensation for its customers for the use of poles that are part of rate base, and an acceptable rate for Nova Scotia communications utilities. The utility would prefer to apply the same rate used by NS Power to maintain consistency in pole attachment fees across the province.

[133] RELC did not include the additional revenue from the pole attachment charge increase in the test year in the Rate Study. Ms. Zarnett indicated that there were only a small number of poles.

#### 3.4.8.1 Findings

[134] The Board observes there was no interventions or challenges to RELC's proposed pole attachment charge. The current charge has been in effect since at least 2010 and the evidence indicates that the utility is not recovering its costs from the current fee level.

[135] Prior to the close of the hearing, the Board released *NS Power 2023-2024 Rate Application* and approved the proposal for NS Power's pole attachment charge of $22.00. The Board is satisfied that the proposed pole attachment charge represents a fair and reasonable estimate.

[136] The Board approves the pole attachment charge of $22 per pole/per year, and the related amendment to Schedule B – Schedule of Rules and Regulations (Regulation 11) and directs the utility to include the impact of the new rates in the test year revenue in the compliance filing.

### 3.5 Deferral of NS Power Costs

[137] RELC's application requested approval to maintain a deferral account for any liability associated with power purchases from NS Power commencing January 1,

2023, for which NS Power has received or may receive approval from the Board to recover from RELC in a period after the purchases were made. RELC advised that if balances accumulated in this deferral, it would apply to the Board for recovery through rates or rate riders on such terms as may be approved by the Board.

[138] RELC provided additional details about this proposed deferral account in its response to Board IR-11 (Exhibit R-12). RELC said it was concerned that if NS Power did not recover its revenue requirement in 2023 (and beyond), RELC may be called upon at some future time beyond 2023 to pay the unrecovered 2023 shortfall in NS Power's revenue requirement. RELC noted that it may or may not be a customer of NS Power in the future period when it might be obliged to pay something to NS Power.

[139] RELC also considered that the existing flow-through mechanism in its tariff would not serve the same function as its proposed deferral account. In response to Synapse IR-14 (Exhibit R-13), RELC said the formula used in its flow-through applications is based on a two-year purchase history from NS Power and noted that in the past two years it bought no energy except for back-up energy from NS Power.

[140] In her evidence, Ms. Whited considered RELC's proposal for a deferral account to be reasonable. She said increased purchased power costs from NS Power are both unknown and outside of RELC's control. She added it was not apparent that the existing flow-through mechanism could be leveraged to address RELC's concern. She recommended that the Board approve RELC's proposed deferral but require the utility to apply for approval to recover any amounts accumulated in the account over a period to be determined by the Board.

### 3.5.1 Findings

[141] The only existing mechanism under which NS Power could seek the recovery of purchased power costs in a prior period from RELC is NS Power's fuel adjustment mechanism (FAM). If RELC remains a customer of NS Power in a future period when FAM adjustments occur, RELC should be able to recover those amounts through its existing flow-through mechanism.

[142] The Board notes that RELC's existing tariff includes a few flow-through mechanisms. One applies to NS Power general rate increases, one applies to an energy-only increase, and a third relates specifically to demand side management (DSM) and FAM changes. Only the energy-only increase formula includes a calculation based upon power purchased from NS Power in a prior period and it is only for the last fiscal year, not two years. The FAM flow-through mechanism uses calculations of energy purchased over a "test period."

[143] The Board recognizes that Section 3.1 of NS Power's current FAM Plan of Administration provides that fuel cost imbalances for a customer that transitions all or part of its load from a FAM class to a non-FAM class may be subject to adjustments occurring after the customer has departed. The Plan of Administration was not filed in this proceeding, but states:

> **3.1 Treatment of load migrating to non-FAM classes**
>
> When a customer transitions some or all of its load from a FAM-class to a non-FAM class, NS Power shall determine the customer's outstanding fuel cost imbalance at the date of transition. This determined imbalance will be adjusted in accordance with UARB decisions in subsequent FAM proceedings relating to the period in question (i.e. FAM AA/BA proceedings or a FAM Audit proceeding). The adjustments will be subject to UARB approval.
>
> The outstanding balance and subsequent adjustments will be paid (or reimbursed) in full on reasonable terms acceptable to the customer and NS Power, or if the parties are unable to agree, as determined by the UARB. Where payment is made over time, the transitioning

> customer shall pay, in addition, any carrying costs such that remaining customers and NS Power are kept whole.
>
> [M10431, Exhibit N-24, OE-01R Attachment 1, p. 11]

[144] If, in the future, RELC is required to make such a payment under s. 3.1 of the Plan of Administration to NS Power (or any identical circumstances for DSM, if applicable), RELC may include that payment in a regulatory deferral for later recovery from its customers upon application to the Board. Since imbalances of this nature may also produce a credit, any payment received by RELC from NS Power must be similarly held in a regulatory account, and in such a case, RELC is directed to apply to the Board to determine how the credit will be applied to benefit its customers.

[145] The use of a deferral account to account for adjustments other than these imbalances is too speculative at this point. A deferral to account for these hypothetical adjustments is denied. If NS Power applies for another mechanism under which other costs could be recovered from RELC, then the Board expects that RELC would receive notice before it is approved. RELC could bring an application to the Board to address the matter at that time.

[146] Finally, the Board recognizes that RELC's purchased power arrangements have become more complex than when the existing flow-through mechanisms in its tariffs were originally developed. When NS Power was RELC's only supplier, the flow-through mechanisms provided an efficient means for RELC to flow-through cost increases to its customers. In a more complex arrangement, where NS Power is only providing part of RELC's supply, it is possible that increasing costs for the purchase of energy from NS Power may be offset by decreases from other suppliers. In such a case, the flowing through of cost increases from NS Power may not be appropriate.

[147] The Board directs RELC, in its next GRA, to address whether, considering the recent complexity of its purchased power arrangements, the existing flow-through mechanisms should continue. As part of this, RELC may wish to consider, on its own or in consultation with one or more other municipal electric utilities, whether another mechanism should be developed to facilitate a timely and fair recovery of purchased power costs. A purchased power adjustment mechanism that would only pass along actual purchased power costs to RELC's customers could be such a mechanism, although it would necessarily entail robust tracking and auditing processes that would place an increased administrative burden on the utility.

## 3.6 Future Studies and Proceedings

[148] RELC emphasized several areas where it intends to focus, including:

- engaging a consultant to undertake a system-loss study (in two phases) in 2023 (Transcript, February 1, 2023, pp. 67-68);
- "…the recommendation by the Board's consultant to file a proposal within the next 18 months to enhance the data and analysis used to develop cost allocation factors and rates" (Exhibit R-17, p. 1);
- "…the recommendations to review the existing declining block rate structure." (Exhibit R-17, p. 1); and
- Working towards a review of the 1920s statute that established RELC (Transcript, February 2, 2023, Part A, p. 189).

[149] RELC was also asked about its research and studies related to return on equity, pole attachment fees, lead-lag, and 400-amp service. Cost, staff capacity and data availability were challenges in many of these areas.

### 3.6.1 Findings

[150] The Board is pleased that RELC has undertaken an asset management program that maps their assets and provides a condition assessment. The Board is also

encouraged by Ms. Bain's statements about records management and financial management, including the Town of Mahone Bay's agreement to provide accounting and financial services to RELC. These initiatives should provide critical data and research information for RELC.

[151] An underlying theme in this hearing has been a clear lack of studies, analysis and data that is specific to RELC. Clearly, the dearth of such information presents a challenge to RELC in making key decisions around its operations, its cost-of-service, and its rate structure. At the same time, it is evident that, as a small utility, RELC does not have the underlying staff and financial capacity to easily remedy this situation.

[152] While the Board desires stronger supporting research for RELC's rates, it understands there are limits to how much can be accomplished and how quickly. The Board appreciates that work such as this must be prioritized and staggered over a longer period.

[153] The Board is encouraged to see the level of cooperation that exists between RELC and some of the other small utilities in the province, as well as the role played by AREA, including the possibility of training and mentorship. Such cooperation could help reduce the pressure on RELC to produce its own specific analysis and studies. The Board would encourage such further cooperation and would welcome studies and analysis that are specific to not only RELC, but the larger community of small utilities.

[154] The Board directs RELC, at its next GRA or within 24 months, to identify which formal studies it has or expects to undertake and the status of any joint training or research activities undertaken or planned with the other municipal utilities or AREA.

## 4.0 SUMMARY

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

- RELC must revise its revenue requirement to account for:
    - reduced power purchase costs from NS Power's approved rates;
    - removal of the proposed $15,000 for storm restoration;
    - the correction for the accounting treatment of contributed capital;
    - revenue from pole attachment fees based on the charge approved in this decision;
    - updated working capital based on 10% of the net cash expense after all the adjustments required by this decision; and
    - a return on equity of 7.5%.
- RELC's proposed rates are to incorporate the following cost-of-service and rate design changes:
    - classify transformer costs as 100% demand-related;
    - include meter costs in computing the ratio of classified distribution plant;
    - adjust rates using the three-step process recommended by Ms. Whited;
    - base customer service charge for Domestic Service on costs classified as customer-related in the cost-of-service study; and
    - the new tariff for a Cable TV Power Packs class is approved, with rates to be provided in the compliance filing.
- RELC's rate increases in 2023 are to be capped at 20% for each rate class, with rates being fully applied effective January 1, 2024, and with any unrecovered revenue from 2023 to be deferred for future recovery, upon

application to the Board, beginning January 1, 2025 or as otherwise directed; and

- The Board has not approved RELC's requested deferral account for potential future liabilities, but approves the establishment of a deferral account with a more limited scope.

[156] RELC is directed to file a compliance filing, no later than April 28, 2023, to address the changes to its application required by this decision. The compliance filing must include an updated version of Exhibit R-6 (all exhibits) and Exhibit R-1 (Exhibit 7), and a clean and redlined version of the utility's new tariffs and regulations.

[157] RELC is further directed as follows:

- To establish a sub-account for storm recovery costs and track them through its existing accounting software, or in a spreadsheet if this cannot be done through its accounting system;
- To complete a system-loss study before its next GRA;
- To review whether maintaining the second block rate can be justified from a cost perspective, and return to the Board with the results of its analysis in its next GRA; and
- To identify, at its next GRA or within 24 months, which formal studies it has or expects to undertake and the status of any joint training or research activities undertaken or planned with the other municipal utilities or AREA.

[158] An Order will issue accordingly.

**DATED** at Halifax, Nova Scotia, this 13th day of April, 2023.

Stephen T. McGrath

Julia E. Clark

Bruce H. Fisher