

NOVA SCOTIA ENERGY BOARD

IN THE MATTER OF THE GAS DISTRIBUTION ACT

- and -

IN THE MATTER OF A GENERAL RATE APPLICATION by **EASTWARD ENERGY INCORPORATED** for the approval of amendments to its Schedule of Rates, Tolls and Charges for the years 2027, 2028 and 2029

BEFORE: Richard J. Melanson, Panel Chair
Steven M. Murphy, MBA, P.Eng., Member
Darlene Willcott, LL.B., Member

APPLICANT: **EASTWARD ENERGY INC.**
David MacDougall, Counsel
Melanie Gillis, Counsel

INTERVENORS: **CONSUMER ADVOCATE**
David J. Roberts, Counsel
Michael Murphy, Counsel

**DALHOUSIE UNIVERSITY and
MICHELIN NORTH AMERICA (CANADA) INC.**
Nancy G. Rubin, K.C.
Brianne Rudderham, Counsel

NOVA SCOTIA DEPARTMENT OF ENERGY
Thomas Kayter, Counsel

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

HEARING DATE: June 22, 2026

FINAL SUBMISSIONS: July 21, 2026

DECISION DATE: **October 13, 2026**

DECISION: **The application is approved, as modified by a settlement agreement, and subject to a compliance filing with directives as set out in Section 5 of this decision.**

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1.0 SUMMARY

[1] Eastward Energy Incorporated (formerly named Heritage Gas Ltd.) applied to the Board for approval of amendments to its Schedule of Rates, Tolls and Charges for 2027, 2028 and 2029. Eastward Energy's last general rate application for an increase to its rates was considered in the Nova Scotia Utility and Review Board's decision setting 2024-2026 rates.

[2] Eastward filed a settlement agreement on June 16, 2026. The settlement agreement addressed most of the issues that had been raised in this proceeding by the Intervenor. The Board finds that the settlement agreement arrives at a reasonable compromise in relation to the various issue on which expert consultants disagreed.

[3] The terms of the settlement agreement are set out in Section 3 of this Decision. The Board approves it, subject to additional directives set out in this Decision.

2.0 BACKGROUND

[4] The general rate application (application or GRA) was filed on February 2, 2026, by Eastward Energy for approval of changes to its Rates, Tolls and Charges. Eastward's last general rate application was before the Nova Scotia Utility and Review Board (NSUARB), which approved rates for 2024-2026 (2023 NSUARB 166 (M10960)) (2024-2026 GRA Decision). The application is made under s.21 of the *Gas Distribution Act*, SNS 1997, c.4. The Board does not regulate the cost of the natural gas commodity nor the cost of carbon. The requested rate increases only apply to the distribution portion of the customer bills.

[5] On April 1, 2025, on proclamation of the *Energy and Regulatory Boards Act*, SNS 2024, c 2, Schedule A, the Nova Scotia Energy Board (NSEB or Board) succeeded the NSUARB for all matters under the *Gas Distribution Act*.

[6] On February 7, 2003, the NSUARB granted Eastward a full regulation class franchise to construct and operate a gas delivery system for a period of 25 years in the counties of Cumberland, Colchester, Pictou and Halifax, the Municipality of the District of East Hants and the Goldboro area of the Municipality of the District of Guysborough (2003 NSUARB 8). The existing franchise rights will expire within the proposed test period. In its application, the Company stated it intends to apply to renew its franchise for another 25 years before it expires in 2028.

[7] Eastward Energy asked to maintain its existing rate class structure, which was changed in the NSUARB's 2024-2026 *GRA* Decision. Eastward only proposed rate increases to the Residential Service Class (RSC). There is a proposed increase to the fixed monthly customer charge for the General Service Class (GSC), but a decrease to the base energy charge for this class for the first 15 GJs/month. The average impact of the proposed rate increases on customers' distribution rates, in each rate class, is summarized in the following table:

Impact of Distribution Rate Design on Rate Classes			
<u>Year</u>	<u>Residential Service</u>	<u>General Service</u>	<u>Rate Class 3</u>
	<u>Class</u>	<u>Class</u>	
2027	7.0%	0.0%	0.0%
2028	8.0%	0.0%	0.0%
2029	9.0%	0.0%	0.0%

[8] The proposed monthly average distribution related bill increases in the application are summarized in the following table:

<u>Year</u>	<u>Residential Service</u> <u>Class</u>	<u>General Service</u> <u>Class</u>	<u>Rate Class 3</u>
2027	\$6.85	0.0%	0.0%
2028	\$8.26	0.0%	0.0%
2029	\$9.91	0.0%	0.0%

[9] If approved, the proposed rates would be as follows:

Fixed monthly customer charge (\$ per month)					
<u>Year</u>	<u>Residential Service</u>	<u>General Service</u>			<u>Rate Class 3</u>
2026 Approved Rates	29.00	65.00			1995.54
Requested for 2027	30.00	67.50			1995.54
Requested for 2028	31.00	70.00			1995.54
Requested for 2029	32.00	72.50			1995.54

Base energy charge (\$ per gigajoule)					
<u>Year</u>	<u>Residential Service</u>	<u>General Service</u>			<u>Rate Class 3</u>
	<u>All volumes</u>	<u>First 15 GJs/Month</u>	<u>Next 400 GJs/Month</u>	<u>Additional</u>	<u>All volumes</u>
2026 Approved Rates	12.349	9.142	5.943	5.693	0.167
Requested for 2027	13.398	8.931	5.943	5.693	0.167
Requested for 2028	14.724	8.722	5.943	5.693	0.167
Requested for 2029	16.376	8.514	5.943	5.693	0.167

[10] Eastward Energy also requested the following:

- To increase its allowed return on equity from 10.65% to 10.80%, maintaining its cost of debt of 6.95% for existing debt, a proposed methodology to calculate the cost of debt for new debt issuances and refinancing of existing debt, and a debt/equity ratio of 55/45;
- An increase of \$5.5 million in its revenue requirement from \$51.7 million in 2026 to \$57.2 million in 2029;
- Continuation of the flexible Deferral Recovery Rate Rider, with adjustments, to continue recovery of Revenue Deficiency Account (RDA) deferral and then begin recovery of the Customer Retention Program (CRP) deferral and a continuation of the allowed 4% return on the CRP deferral balance;
- Continuing the deferrals for the RDA and CRP, but reducing the cap on the RDA from \$50 million to \$25 million;
- A proposed new methodology for the treatment of income taxes in cash working capital;
- Continuing the Incentive Program for new multi-unit residential buildings and single-family homes, with adjustments;

- Changes to the weather normalization policy, related to the use of historical averages; and
- Amendments to the Distribution Service Rules, including revisions to fees and charges.

[11] A number of formal Intervenors responded to Eastward's application and participated in the hearing, including the Consumer Advocate (CA); Dalhousie University (Dalhousie); Michelin North America (Canada) Inc. (Michelin); and the Nova Scotia Department of Energy (NSDOE).

[12] The Notice of Public Hearing advised members of the public that they could file letters of comment with the Board about Eastward's application, or request to speak at an evening session. The Board received no letters of comment or requests to speak at an evening session.

3.0 SETTLEMENT AGREEMENT

[13] On June 16, 2026, Eastward filed a settlement agreement with the Board proposing to resolve most of the issues in the general rate application. All the Intervenors, except the NSDOE, signed the settlement agreement. In his Opening Statement, while indicating that NSDOE's key concerns in this matter related to forecast capital expenditures, and their treatment in rate base, including return on equity, Thomas Kayter, Counsel for the NSDOE, did not oppose the settlement agreement. While acknowledging that negotiated settlements can serve ratepayers and utility interests alike, Mr. Kayter said: "...the Province respects the Board's independent role in reviewing the evidence before it, including the terms of any settlement..." The NSDOE's position reflects the law

around settlement agreements that ultimately, it is the Board and not the parties, that must set just and reasonable rates.

3.1 Settlement Agreement Between Eastward, Consumer Advocate, Dalhousie and Michelin

[14] The settlement terms were set out in a schedule to the settlement agreement which provided as follows:

SCHEDULE "A"

Terms of Settlement

Application Element	Settlement Terms
Return on Equity	10.7% with an equity thickness of 45%.
Depreciation	Begin utilizing the ALG procedure starting in 2027 as discussed in the testimony of Mr. Bowman. Conduct a depreciation study for the next GRA which includes assessment of net salvage values for the next test period and assessment of revised account values, average service lives and amortization as discussed in the testimony of Mr. Madsen. Ensure the next depreciation study is IFRS compliant if Eastward determines it will be transitioning to IFRS.
Customer Rates	Reduce the residential (RSC) rate increases to 4.75% annually (cumulative 14.9%) and in 2027 reduce the GSC rates by 1.1% and reduce the RC3 rates by 2.0%.
Debt	As per the Application.
Deferral Recovery	As per the Application, with the exception that the rate rider cap will be lowered from a \$1.50/GJ to \$1.00/GJ for the RSC and GSC classes and to \$0.65/GJ for the RC3 class. Any discretionary reductions to the rider cap will be applied proportionately.
Customer Incentive Program	Maintain the program as per the Application.
Cost of Service	Maintain the DWAL method for mains allocation as per the application. Eastward shall investigate and put forward a proposal for consideration in its next GRA in relation to recovery of the cost of steel and plastic mains as raised by Mr. Bowman in the first paragraph of his response to Eastward IR-2. Maintain the Marketing & Sales allocation as per the application.
Other	All other elements of the Application to be maintained as filed other than the following items as agreed to in Eastward's Rebuttal Submission: preparation of an analysis of total forecast additions versus actual customer additions over the 2027-

	2029 test period in the next GRA, including explanations of any major variances. • to provide annual capital reports for permits to construct in a manner similar to current MFT projects, as part of Eastward's annual Financial Compliance report. • to conduct a comprehensive review of Eastward's capitalization policy with any changes brought forward in the next GRA. • to report to the Board in 2027 once a decision is made on whether an IFRS transition will occur and to provide transition timelines. • to report for the next GRA on the IFRS transition analysis, related IT system requirements, including time carding and capital modules, the review of Eastward's capitalization policy against IAS 16, and an IFRS-compliant depreciation study if an IFRS transition is confirmed, and • to prepare an updated Lead Lag study for the next GRA.
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[Exhibit E-35, pp.6-9]

3.2 The Board's Approach to Settlement Agreements

[15] The Board's approach to settlement agreements was discussed in Eastward's last GRA. In *Eastward Energy Incorporated (Formerly Heritage Gas) (Re)*, 2023 NSUARB 166, the NSUARB said:

[47] In its previous decisions, the Board has set out the principles it applies in its consideration of settlement agreements. Those principles bear repeating. In its decision dated November 5, 2008, about a NS Power general rate application, the Board outlined its general approach to settlement agreements submitted to it for approval:

[12] The Board's *Regulatory Rules* facilitate settlement discussions. The Board welcomes and appreciates the efforts of parties to, in good faith, settle issues, even where, as sometimes happens, a settlement cannot be ultimately achieved.

[13] Where, as here, the Agreement is supported by representatives of all of the customer classes, the Board can have confidence that the Agreement is in the public interest.

[14] Customers of NSPI and members of the public are, perhaps understandably, wary of the settlement process. Many of those customers and members of the public may not appreciate that by the time the hearing commences 80% of the rate hearing process has already happened. NSPI filed extensive evidence, as required by the Board, to support its rate request. Interested parties and Board Staff asked NSPI many hundreds of written questions (Information Requests), to which responses were filed.

[15] All of the parties who chose to do so filed evidence, including expert evidence. Written questions (Information Requests) have been asked of and answered by interested parties who filed evidence. NSPI filed reply evidence. As noted, all of this happened before the hearing was scheduled to begin so that the parties and the Board are well informed about the case in advance of any oral public hearing.

[16] The public can rest assured that the Board Members hearing the matter have also thoroughly reviewed all of the material in advance of coming to a decision as to whether to approve the Agreement as being in the public interest.

[17] Settlement agreements, while relatively new in regulatory matters before the Board, are common in the litigation process. Within the Board's adjudicative mandate, for example, assessment appeals, planning appeals and other matters are often settled. In the civil courts of Nova Scotia, a much higher percentage of cases are settled than go to trial.

[18] That is not to say that the Board would hesitate to reject a settlement agreement it did not consider to be in the public interest, however, it should be understood that a properly supported settlement is a success of the regulatory process, not a failure.

[2008 NSUARB 140]

[48] The Board remains mindful that, in its consideration of settlement agreements, its ultimate duty is to ensure that the terms of agreement are just, reasonable and in the public interest:

[23] ...Settlement agreements do not, however, diminish the Board's duty and obligation to ensure that the terms of any such agreement result in approval of only those costs which are fair, justifiable and prudently incurred by the Utility. Further, the Board must ensure that these costs result in customer rates that are just, reasonable and in the public interest. In addition, when deciding whether to approve a settlement agreement, the Board must be satisfied that the outstanding concerns of all intervenors are adequately considered by the Board and the terms and conditions under which they consent to a settlement agreement are honoured.

[NS Power 2007 GRA decision, 2007 NSUARB 8]

[16] The foregoing principles are equally applicable to this matter.

3.3 The Board's Approval of the Settlement Agreement

[17] All the signatories to the settlement agreement expressed support for it in their Opening Statements. Nancy K. Rubin, K.C., Counsel for Michelin and Dalhousie provided a good summary of the process that led to the settlement and its outcome:

Unlike the NSPI GRA, the process followed in this case took the more common path where Eastward filed extensive evidence in support of its Application and responded to wide-

ranging IRs. Expert evidence was then filed on behalf of the Consumer Advocate, Board counsel, and Michelin/Dalhousie, each of which was further tested by IRs. Eastward filed rebuttal evidence, and only then did the parties reach a final settlement. The Board can therefore approach this Settlement Agreement with confidence that all perspectives were analyzed, considered and tested, and that the compromises reflected in the Agreement are properly informed.

The settlement balances the recommendations of consultants. Where they differed, the parties negotiated terms that honour the underlying regulatory principles advanced by each: cost causation, rate stability, intergenerational equity, and long-term system sustainability.

[Exhibit E-39, pp.1-2]

[18] In addition to the evidence being tested through Information Requests (IRs) and experts' reports, there was a one-day oral hearing, which consisted primarily of the Board probing and testing the evidentiary filings. The Board has a complete record upon which to assess the settlement agreement. While there were many contested issues raised by the various experts retained by the parties and Board Counsel, they were all either resolved by the terms of the settlement agreement, or by a commitment on Eastward's part to further study certain issues. While not all expert witnesses were fully supportive of how the various issues were resolved, there was a general acknowledgement that the settlement agreement provided a reasonable compromise that arrived at supportable rates.

[19] The Board has reviewed the evidence and submissions presented in this matter. The parties to the settlement agreement collectively receive service under all Eastward's rate classes. The Board is satisfied that the settlement agreement is in the public interest. The terms of the settlement agreement provide rates that are, for the most, materially lower than proposed in the application, based on supportable public utility regulatory principles, without compromising the financial integrity of the utility. The Board will now explain why that is the case.

4.0 ANALYSIS AND FINDINGS

4.1 OMA Costs, Rate Base and Revenue Requirement

[20] In its application, Eastward presented net revenue requirements, including the amounts for recovery of the RDA and CRP through the rate rider, ranging from \$66.1 million in 2027 to \$70.7 million in 2029. The response to Undertaking U-1, Attachment 1 – Revenue Requirement Reconciliation, Excel (Exhibit E-46(i)), indicated that these amounts were reduced by approximately \$7 million in each year in the settlement agreement.

[21] Operating Maintenance and Administrative (OMA) expenses have increased since Eastward's last GRA due to inflation and labour adjustments to attract and retain employees. Net of capitalized amounts, OMA costs account for a significant portion of Eastward's forecast revenue requirement across the test period. In general, no party challenged the OMA expenses, working capital and the lead/lag study, net plant in service or income taxes. As part of the settlement agreement Eastward committed to preparing an updated lead/lag study for its next GRA.

[22] Eastward forecasted its rate base to grow from \$338.7 million in 2027 to \$390.5 million in 2029, driven primarily by \$103 million in total capital additions over the test period, consisting of \$17.8 million in 2027, \$31.8 million in 2028, and \$53.4 million in 2029. This capital program fuels Eastward's required revenue growth, with major projects like the Bedford Loop Project and the Trenton Interconnection targeting long-term expansion capacity and system redundancy. The proposed capital expenditures are broken down as follows:

Figure 5-5 - Capital Expenditures by Project (Net Additions) (\$Millions)³⁰

Total Capital (\$ in Millions)	2026B	2027F	2028F	2029F	3-Yr. Total
New Business	7.4	9.5	9.1	12.2	30.8
Energy Evolution	-	-	-	4.0	4.0
Bedford Loop Project	-	-	10.6	4.5	15.1
Trenton Interconnection	-	-	-	17.5	17.5
Interconnection 1	-	-	-	7.0	7.0
Interconnection 2	-	-	-	-	-
GTA Incentive Program	1.3	1.3	1.3	1.3	3.9
System Betterment*	1.0	1.5	1.8	1.2	4.5
General Plant	1.0	0.9	4.2	0.9	6.0
Capitalized OMA**	4.6	4.6	4.7	4.9	14.2
Total Forecasted Capex	15.3	17.8	31.8	53.4	103.0
* Includes Port Wallace Reinforcement Project					
** Capitalized OMA forecasted at 26%					

[Exhibit E-20, p.34]

[23] In its Opening Statement, the NSDOE urged caution regarding major 2029 capital projects, such as the Bedford Loop and Interconnections, because they remain contingent on future approvals and uncertain scopes. It argued that the Board should not automatically permit full Weighted Average Cost of Capital (WACC) rate base treatment for unconfirmed projects. While unspent capital could potentially be addressed through the RDA, the NSDOE recommended that the Board review this mechanism or direct Eastward to implement a true-up process to remove unspent or unapproved capital from the rate base, thereby protecting customers from unnecessary carrying costs.

[24] Undertaking U-1 provided the full reconciliation of changes to revenue requirements from the original application to the settlement agreement. The variance analysis shows that the return on rate base and plant amortization accounts were impacted by lower property, plant and equipment (PP&E) investments in Q4 2025 (actuals

vs forecast). This was partially offset by higher asset balances resulting from reduced amortization and recoveries, alongside the adoption of the Average Life Group (ALG) depreciation method. The recovery timelines for the RDA and CRP will also be delayed and have higher carrying balances due to the settlement agreement's lower deferral recovery rates throughout the test period. Income taxes, tax provisions and other revenues decreased due to lower overall revenues driven by lower base rates and reduced customer attachments levels in Q4 2025.

4.1.1 Findings

[25] The revenue requirements and rate base resulting from the settlement agreement are reasonable. The Board directs Eastward to update the lead/lag study in its next general rate application.

[26] Regarding the NSDOE's recommendation to remove unspent capital from rate base, the current practice is for capital projects to be added to rate base only when the funds are spent. Any excess revenues generated from a higher than actual forecast of capital additions will automatically be applied to reduce the RDA. Consequently, there would be no unnecessary carrying costs incurred by customers related to lower than forecast capital additions.

4.2 Cost of Service Study, including Class Allocation

[27] Eastward's application noted that most cost allocation methodologies remain identical to those used in its 2023 GRA. However, pursuant to a 2023 GRA directive, Eastward was directed to evaluate alternative options for allocating mains and marketing costs.

[28] Eastward's consultant, SME Professional Consulting Inc. (SME), provided a Cost Allocation and Rate Design Study as part of the application. SME recommended

that accounting costs be functionalized like all other indirect labour instead of being captured with marketing and sales costs. The remaining costs, consisting of labour costs for the marketing and sales department and advertising and promotion expenses, would be captured as marketing and sales costs and allocated 50% to site and 50% to energy.

[29] The Consumer Advocate's consultant, John D. Wilson, Vice-President of Grid Strategies LLC, agreed with shifting accounting costs to indirect labour but opposed the proposed 50% site and 50% energy allocation split for marketing and sales costs. Mr. Wilson noted an inconsistency with earlier filings, where Eastward previously suggested direct marketing and sales costs were energy related and accounting costs were site driven. He argued that Eastward provided insufficient evidence that both factors now influence marketing and sales activities or that marketing and sales costs scale with customer growth. Mr. Wilson recommended allocating marketing and sales solely based on class energy, which would reduce the residential cost share from 32.4% to 4.6% and yield an average annual bill savings of \$132 per residential customer.

[30] Dalhousie and Michelin's consultant, Patrick Bowman, of Bowman Economic Consulting Inc., argued from a cost-causation perspective that marketing and sales activities primarily drive customer additions rather than energy consumption. He cited Eastward's evidence showing a projected 11.1% increase in customer sites over the test period compared to only a 4.6% increase in total energy throughput. Mr. Bowman also noted that the benefits of customer growth vary by class: residential and small commercial customers benefit from spreading site related costs over a broader base, whereas large RC3 customers derive minimal benefit because their allocations are largely

unaffected by customer counts. Mr. Bowman recommended revising the marketing and sales cost allocation methodology to a 1/3 energy and 2/3 site split.

[31] In its Rebuttal Evidence, Eastward defended its 50% site and 50% energy split as a balanced compromise between the Wilson and Bowman proposals. Ultimately, through the settlement agreement, Eastward and the participating parties agreed to adopt the 50% site and 50% energy allocation methodology for marketing and sales costs.

[32] Owning and operating mains represent the most significant cost of providing service, accounting for approximately half of the functionalized revenue requirement. As such, it is critical that these costs be classified and allocated to each of the customer rate classes in as thoughtful a manner as possible. The SME report reviewed common methods used for allocating mains costs and associated issues and continued to recommend the Demand Weighted Actual Lengths (DWAL) method used in the 2023 GRA because it incorporates both pipe length and peak demand, treating mains costs as 100% demand related.

[33] Mr. Bowman critiqued Eastward's proposed mains allocation methods, and argued that the DWAL approach relies on proprietary pressure modeling that is not transparent and reflects peak "use" rather than cost causation.

[34] Mr. Bowman recommended the Minimum System Study (MSS) method for low-pressure plastic mains cost allocation, resulting in 91% site related and 9% demand related allocation. Mr. Bowman argued that the MSS is superior and standard across Canada. Mr. Bowman said that the MSS avoids allocating low pressure mains costs to large RC3 customers who are served by the elevated pressure system and do not use those mains. Mr. Bowman also recommended no load carrying capacity adjustments to

the MSS as it would only impact 9% of mains costs classified as demand related which would make an immaterial financial difference.

[35] In its Rebuttal Evidence, Eastward defended its DWAL approach, arguing that the MSS relies on flawed assumptions for Eastward's specific network such as using customer counts as a proxy for geography and omitting load capacity. Eastward maintained that DWAL more accurately reflects actual system usage by current customers, incorporating factors like large anchor customers, shared downstream use, looping, and system reinforcement.

[36] Mr. Bowman's response to Eastward's IR-2 raised an additional issue as follows:

First, Mr. Bowman notes that the larger RC3 customers would be connected via the Elevated Pressure system and should not be allocated any costs of low-pressure Distribution Mains. The DWAL method is clear that costs associated with Mains do not lead to any allocation to the RC3 class related to customers that do not use Mains (Exhibit E-1, pdf page 464). However, the rate design does not appear to then extend this principle to actual rate design for customers who do not use the Mains, per the Eastward Tariff Book (Exhibit E-1, pdf page 530) where all RC3 customer pay the same demand charge, whether connected only to the steel Elevated Pressure system, or also connected to low-pressure Mains. In essence, Eastward proposes to allocate costs differently related to RC3 customers who are connected to Elevated Pressure versus to low-pressure Mains, but then charges all RC3 customers equally so that the Mains costs are shared among customers who do not use Mains. This is a further issue with the Eastward application that was not originally highlighted in Mr. Bowman's evidence but does require adjustment in preparing the final rates to be approved

[Exhibit E-30, p.4]

4.2.1 Findings

[37] Pursuant to the settlement agreement, the Board accepts the continued use of DWAL as an appropriate methodology for mains allocation, and the marketing and sales costs allocation of 50% to site and 50% to energy. Also pursuant to the settlement agreement, the Board directs Eastward to investigate and put forward a proposal in its next GRA in relation to recovery of steel and plastic mains as raised by Mr. Bowman.

4.3 Rate Design

[38] Eastward did not propose any changes to the existing rate class structures in this application. Eastward set out the rate design objectives it seeks to achieve:

- Full Cost Recovery - each rate class fully covers its cost of service, reducing reliance on deferred balances over time.
- Price Competitiveness - important for retaining and attracting customers.
- Fairness between Rate Classes - equitable across customer groups with a target range of Revenue-to-Cost (RC) ratios of 95–105% target.
- Fairness within Rate Classes - charges should closely reflect the actual cost to serve each customer, minimizing cross-subsidization between users within the same class.
- Stability of Rate Structure - transparent and easy-to-understand pricing system.
- Principle of Gradualism - avoid “rate shock.”

[39] The RC ratios and how to address them was raised in the evidentiary filings. In particular, the rates proposed in the application would have moved the RC ratio for the RSC class from 59% in 2027 to 69% in 2029. The GSC and RC3 classes would have gone from 114% in 2027 to 109% and 108% respectively. Eric Borden, Principal Associate of Synapse Energy Economics, Inc. (Synapse) raised concerns that the proposed rates placed all the increases primarily on the Residential Service Class, failing to account for gradualism, since the proposed cumulative residential rate increase was approximately 26%. Eastward said that gradualism was a key consideration, but it had to be balanced against the need to move the residential customers towards full cost recovery.

4.3.1 Findings

[40] There is no doubt that, even with the increases proposed in the application, the Residential Service Class would still have been contributing well below the cost to serve this class. The settlement agreement alleviates much of the concern about gradualism. It does little to bring the residential service class closer to the target range of 95-105%. The settlement agreement brings the Residential Service Class RC ratio to 64.4%. The movement of the residential class to full cost recovery has been a long process. When considered in its totality, insofar as rate design is concerned, the settlement agreement can be justified by placing greater weight in this application on the principle of gradualism than on the need to address cross-subsidization. The Board, therefore, accepts the rate design resulting from the settlement agreement. The Board notes, however, that the RSC class needs to continue to move towards full cost of service recovery over subsequent GRAs.

4.4 Three-Year Test Period, Customer Growth Assumptions and Load Forecast

[41] Most of Eastward's delivery revenue in the three-year test period is forecast to be generated through the continued service of its existing customers. The Company's revenue and load forecast for the test period assumes that its customers are retained and continue to consume gas in similar amounts and patterns as they have in the past, albeit adjusted for changing weather patterns. Per Eastward's response to NSEB IR-25 c), at the end of 2025, Eastward reported that it had 9,558 customers, split between residential (60.1%) and commercial (39.9%).

[42] In terms of estimated new customer growth over the test period, Eastward is forecasting growth that is slightly lower than its historical seven-year average from

2018-2024. Over the test period from 2027 to 2029, the number of customers is forecast to increase by 10%, for an average annual growth rate of approximately 3.5% per year. Eastward expects its new customers will be from two sources: (1) new customers from existing mains (i.e., infill) or short main extensions; and (2) new customers from distribution mains expansion projects. These new customers will join the Residential and General Service Classes, while Eastward forecasts no new RC3 customers over the test period.

[43] The Company's forecast of new customers on existing mains and from distribution expansion of mains that are near existing mains was developed through review and analysis of market potential in combination with supporting construction project plans. Potential customers are categorized by the Eastward sales team based on customer expectations by rate class, market area research, development plans, and historical market acquisition trends. Expected usage for energy source conversion opportunities is based on the premise's historic fuel use, adjusted for increased efficiency of new natural gas equipment. Potential usage for new development sites is estimated based on finished areas, unit counts, proposed equipment specifications, comparison to other new developments of similar size and use with preliminary operating usage available, and output from energy models.

[44] New customers from gas main expansion projects to new developments within Eastward's service areas are forecast based on detailed reviews of specific development plans for each market. Eastward noted that there are significant developments planned around Halifax Regional Municipality (HRM) in the areas of Bedford West, Port Wallace/Parks of Lake Charles, Sandy Lake, Mount Hope and Seton

Ridge. For the current Bedford West development areas and the planned expansions into Port Wallace/Parks of Lake Charles, Seton Ridge and Mount Hope area, Eastward has forecast that 100% of the planned commercial properties (i.e., multi-unit residential buildings or MURBs) will be constructed with natural gas as part of their buildings' energy needs and activated as Eastward's customers. Eastward's forecast also assumes that a majority of the detached new residential properties in these areas, built during the 2027-2029 test period, will use natural gas as part of their energy needs. However, Eastward noted that builders of townhouses and semi-detached residential properties have shown a preference for electrical energy systems due to their lower installation cost and rebate incentives offered by Efficiency Nova Scotia. Eastward has, therefore, not forecast any capture of these customers in the test period.

[45] The following table summarizes the distribution of Eastward's forecast new customers over the test period:

	2027F	2028F	2029F
Infill and Short Main Extension Growth			
RSC Infill	115	115	115
RSC New	80	80	80
GSC	92	90	90
RC3 (Rate Class 3)	-	-	-
New Developments - Expansion Required			
RSC	45	45	65
GSC	18	20	42
RC3	-	-	-
Total	350	350	392

[Exhibit E-1, p. 119]

These customer additions would see Eastward's customer base increase from 9,851 in 2026 to 10,943 in 2029.

[46] To estimate the expected gas consumption per customer over the test period, Eastward performed an analysis of historical weather normalized consumption patterns for customers that were active on December 31, 2024, and had been active for a minimum of 12 months. Weather normalization is used to adjust actual historical volumes to “normal” before being used for forecasting future volumes. As weather trends are unpredictable, the forecast assumes that all future years are “normal”. Eastward’s analysis was conducted for each customer class and resulted in 2024 average annualized weather normalized consumption per customer as follows: RSC customer – 64 GJ, GSC customer – 1,510 GJ and RC3 customer – 169,390 GJ. In addition, Eastward estimated monthly demand for each existing RC3 customer based on existing contracts.

[47] Given the relatively young age of Eastward’s gas distribution system and its customers’ furnaces and boiler systems, the Company is not expecting a material variance in customer gas usage over the test period. As such, the forecast of estimated consumption per customer is anticipated to remain stable over the 2027-2029 test period.

[48] For customers added in a test year, Eastward estimated related gas consumption based on the expected customer activation date and by using an estimate of the customers’ consumption curve over the year. The consumption curve is based on the historical pattern of consumption for similar customers in similar geographic markets. Most Eastward customers use natural gas predominantly for heating purposes, so consumption is weighted more heavily to the winter months. In addition, new customers are typically activated late in the year, prior to the heating season. These timing factors for new customers activated in a forecast year are incorporated into the volume forecast for new customers. Eastward has forecast no new RC3 customers over the test period.

Therefore, monthly demand projections for this customer class are based only on existing RC3 customers.

[49] Eastward's weather normalized customer consumption analysis is currently determined using the 20-year rolling average of heating degree-days (HDD) for weather stations located in Shearwater, Halifax Stanfield International Airport and the Town of Amherst. When using historical consumption data to forecast future consumption, Eastward's analysis involves calculating and applying a weather correction factor for each area. The weather correction factor is the ratio of the current month HDD to the 20-year average heating degree-days. HDD for a given day represents the number of Celsius degrees that the mean temperature is below 18 degrees Celsius. If the temperature is equal to or greater than 18 degrees, then the number will be zero. Values below the base of 18 degrees Celsius are used primarily to estimate the space heating requirement of buildings.

[50] In preparing its GRA application, Eastward completed an analysis of the 20-year HDD average it has historically used to determine weather normalized consumption. Eastward found that over the last 20 years, HDDs have been decreasing by approximately 0.05 HDD/day or 18.25 HDDs/year, with data suggesting that roughly 77% of the time actuals fall short of the 20-year average, typically by about 177 HDDs annually. Given the persistent gap between actuals and the 20-year average, and the fact that Eastward shareholders bear the risk should actual temperature persistently go above or fall below the 20-year average, Eastward believes it would be prudent to adjust the weather normalization method to use a 10-year historical HDD average to account for the downward trend in HDDs over time (associated with warming temperatures).

[51] Eastward noted that moving to a lower historical average has the benefit of reducing the average expected costs associated with weather normalization in the long run. However, it also runs the risk of increasing the volatility/magnitude of weather normalization costs/benefits in any single year. Eastward believes a balance should be struck between normalization costs and volatility, best offered by using a 10-year historical HDD average. Eastward, therefore, has asked for Board approval to change its weather normalization methodology starting in 2027. Eastward also noted that this term aligns with other large Canadian utilities including Enbridge Gas Inc. and ATCO. Eastward further stated that, even with this recommended change, weather normalization impacts and risks continue to be a shareholder burden and are not recovered from customers. Eastward's forecast gas consumption volumes for the 2027 to 2029 test period are based on this change in methodology.

[52] Board Counsel retained Cathcart Advisors, Inc. (Cathcart) to review Eastward's annual customer growth percentage forecasts for the test period and said that they are somewhat consistent with prior years. Cathcart also stated that Eastward uses robust mechanisms to estimate customer penetration and fuel use by mid-year activation. With regard to Eastward's weather normalization process for forecasting gas consumption on a per customer class basis, Cathcart concluded that Eastward's proposal to move to a 10-year HDD average is reasonable and could be considered prudent. Cathcart also stated that Eastward's methodology for forecasting average gas consumption on a per customer basis represents a somewhat conservative approach by forecasting steadily lower volumes per customer that is based on stricter building codes,

more efficient heating equipment and energy retrofits that improve overall annual fuel utilization efficiency.

[53] Mr. Borden reviewed Eastward's annual customer growth percentage forecasts for the test period. He acknowledged that Eastward's projections are based primarily on the Company's market knowledge. However, he stated that based on his review of the filed evidence, the accuracy of Eastward's projections cannot be verified. He further noted that in response to Synapse IR-11b), Eastward provided a comparison of the forecast 2024 to 2026 new customer additions from the Company's 2023 GRA to the actual customer additions over that period. Based on that data, Mr. Borden found that for the two years of recorded data (2024 and 2025), Eastward over-forecasted RSC Infill and RSC New additions by between 1% and 156%. He also found that Eastward's GSC new customer forecasts in 2024 and 2025 were more accurate, where actual additions were more than the forecast by 6% and 19%, respectively. In total, he found that Eastward's forecasted customer additions for 2024 and 2025 exceeded actuals by over 30%.

[54] Based on his analysis, Mr. Borden believes there is a risk that Eastward's forecast of new customer additions over the 2027 to 2029 test period may be too high. He therefore recommended that in its next GRA, Eastward present an analysis of forecast versus actual new customer additions from 2027 to 2029 and explain the discrepancy between the actual and forecast values. He also recommended that Eastward specifically investigate which developments or areas were most inaccurate and then discuss how this can be remedied. Mr. Borden further recommended that Eastward investigate alternative methodologies of new customer addition forecasting using a combination of historical and

forecast information that is more transparent and can also improve forecasting accuracy. He specifically referenced the potential use of regression models that incorporate multiple sets of economic and demographic data to derive customer forecasts.

[55] In its Rebuttal Evidence, Eastward agreed with Mr. Borden's recommendation to provide an analysis of total forecast additions versus actual customer additions over the 2027 to 2029 test period in its next GRA and to include explanations of any major variances. However, regarding Mr. Borden's recommendation to improve forecasting accuracy and transparency, Eastward's Rebuttal Evidence stated that the size of its customer base and its forecast additions do not justify the expenditure required to carry out robust regression models and multiple data sets. Eastward believes that its current forecasting methodologies, with the addition of the analysis of forecast versus actual additions incorporated into the next GRA as recommended by Mr. Borden, reflects an appropriate and prudent level of effort relative to Eastward's size, complexity, and the materiality of the new customer additions to rates and revenues.

4.4.1 Findings

[56] The Board finds that Eastward's existing customers have a reliable gas consumption history on which to base load and revenue forecasts. They therefore present a lower forecast risk for delivery revenue and load than from new customer additions which make up the remaining portion of the Company's revenue forecast over the test period. Further, the number of Eastward's existing customers is much greater than its forecast customer additions. Having a greater proportion of forecast load and revenue from existing customers reduces the degree of potential variability for the forecasts, as a relatively small proportion of the forecast is dependent on new customer additions.

[57] Nevertheless, the Board shared the same concerns as Mr. Borden regarding Eastward's forecast for residential customer growth. The Board explored this issue further during the hearing:

Q. Okay. Thank you.

I have a question on the growth forecast. So I don't know, Mr. Johnston, this may be for you. I'm not sure. It's a relatively short question.

MEMBER MURPHY: Rob, if you can call up Synapse IR-11, Attachment 2? It's one of the attachments I emailed to you.

Maybe just make it a tad smaller.

There we go.

BY MEMBER MURPHY:

Q. So this was a comparison of Eastward's forecasts for residential infills, new residential construction, GSC -- new GSC customers, new RC [sic] customers. It's a comparison of forecast additions that were shown in the 2023 GRA versus what actually happened. And when you look at the numbers, they're actually not that bad, I don't think, except for the RC — RSC infills, and those were quite a bit less. By my math, they were about 43 percent of forecasts. The other ones, I think, were actually pretty good.

So my question is, in that context, and given there was some suggestion in your evidence that the RC infill — RCS potential customers are delaying decisions as it relates to replacing their equipment and whatnot. So in that context, I guess you're projecting in the test years 195 new RSC customers from infills main extensions, which would give 585 customers over the period compared to 220 in 2026 for the last period.

So my question really is, in that context, how can you be confident that you're going to get the projections you're expecting in this particular Rate Application?

A. (Johnston) So the context, in terms of framing the question, is correct. I think what you see here in the general service class, you know, the performance from '24 to '26 was, you know, meeting expectations. What happened on the residential side, there — to your point, there were a lot of residential customers delaying that decision, or — it's the upfront capital costs for a lot of customers, in terms of affordability, that would hinder their decision to either make that commitment. A lot of times, when we've got our sales reps talking to residential customers, they're thinking about an outlay of, you know, 10,000 to 12 or \$15,000 in their homes, and so the upfront capital cost is there.

One of the things that we did, in terms of continuing the incentive program, is to incentivize folks to make that conversion from oil or propane to come to gas, and so having that incentive program helps us to attract those customers, helps us to retain those customers on the residential side to meet those forecasts. It decreased our forecast in this GRA compared to what we did in the 2023 Application, so we feel confident that the forecast we put forth is a prudent and reasonable one.

Q. No, I understand you decreased it, but it's still a fair bit higher than the actuals that occurred from '24 to '26. By my math, your projecting 585 new RSC customers versus 226 or 266 that happened in '24 to '26, recognizing '26 is, I guess, the forecast.

A. (Johnston) Yeah. There's a lot of residential areas around metropolitan Halifax that are under construction, so those lots that get sold off, there's — you know, there's permitting delays, there's labour constraint delays in terms of building those lots and infrastructure, but we still feel like we've been conservative and prudent, and we think it's a customer number that we can meet.

[Transcript, pp. 150-154]

[58] The Board accepts Eastward's explanation and trusts that the Company's customer growth targets over the test period can be met. Further, the Board finds that Eastward's projections over the test period for new infill or short main extension customers are supported by sound data and information. The Board also notes Eastward's response to NSEB IR-86, where the Company indicated that the revenue impact of its forecast new customer additions is roughly only 1% in each test year. As such, the Board finds that any variations from Eastward's customer growth forecasts over the test period would not have a material impact on rates and actual revenues collected.

[59] This notwithstanding, the Board accepts Mr. Borden's recommendation that in its next GRA, Eastward present an analysis of forecast versus actual new customer additions from the 2027 to 2029 test period and explain the discrepancy between the actual and forecast values. Eastward agreed to this recommendation, and the recommendation has been incorporated into the settlement agreement. As such, the Board directs Eastward to provide such an analysis in its next GRA.

[60] The Board, however, agrees with Eastward that Mr. Borden's recommendation for Eastward to investigate alternative methodologies of new customer addition forecasting using a combination of historical and forecast information using regression models is not warranted at this time. This finding is primarily based on the

Board's belief that the cost of such an exercise is not merited given that variations in Eastward's customer forecasts are not expected to have a material impact on rates and actual revenues collected over the test period.

[61] In addition, the Board finds that the proposed weather normalization process used by Eastward to estimate normalized gas consumption per customer class is appropriate. This process allows for more consistent year over year customer consumption comparisons. Given a consistent trend in warmer weather over the past 20 plus years, Eastward has proposed changing the calculation methodology for its weather normalization factor by reducing the 20-year rolling average of heating degree days to a 10-year historical average. Eastward argued that this would be more reflective of current and future temperatures.

[62] Based on the identified benefits of this proposed change in methodology, Cathcart found Eastward's proposal to be reasonable and could be considered prudent. The Board agrees. Eastward's proposal to move to the 10-year HDD average will prevent systematic over-forecasting of demand and minimize resultant deferrals necessary to recover foregone load and revenue. The proposal would also result in Eastward's methodology being consistent with other jurisdictions in North America. Further, the change to the weather normalization process has been accepted in the settlement agreement. The Board, therefore, accepts Eastward's proposal to move to the 10-year HDD average in its weather normalization process.

[63] Based on the above, the Board finds that Eastward's load and delivery revenue forecasts over the test period are acceptable.

[64] The Board makes one final comment related to Eastward's longer-term gas consumption projections. In response to NSEB IR-28, Eastward noted that it had discussions with NS Power about the potential conversion of the Trenton Generating Station to natural gas from coal. In addition, Eastward indicated that it has more recently been engaged with the Nova Scotia Independent Energy System Operator (IESO NS) about two proposed fast-acting natural gas-fired generating plants that are working their way through the IESO NS procurement process. Given Eastward's existing franchise area to distribute natural gas in Pictou County, Eastward believes these three sites, when built or converted, would be served with natural gas delivered by Eastward. Eastward also noted that for the purposes of forecasting, Eastward assumed serving the three interconnections with the estimated related incremental annual gas usage for each to be 2.9 million GJs starting in 2030, 2031 and 2033.

[65] During the hearing, Eastward confirmed that there are no revenue requirements associated with these interconnections in the 2027-2029 test period. At this point the advancement of the projects has yet to be confirmed. In particular, the conversion of NS Power's Trenton generating station to natural gas seems doubtful given IESO NS's 10-year System Outlook, which forecasts that facility being retired in 2030. The Board only notes these interconnections at this point, as Eastward's collection timeline for the CRP deferral assumes these projects will proceed. If they do not, Eastward's future gas usage forecasts will likely be lower than forecast. In such a case, collection of the CRP deferral would occur over a longer period than currently envisioned.

4.5 Depreciation

[66] Depreciation, in public utility regulation, is the loss in service value of an asset not restored by current maintenance, incurred in connection with the consumption

or prospective retirement of the asset. As used in accounting, it is a method of distributing fixed capital costs over a period of time by allocating annual amounts to expense. Depreciation expense is an estimate of the consumption of the economic value of an asset over its expected service life. Each annual amount of such depreciation expense is part of that year's total cost of providing natural gas distribution utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service - that is, the item's service life. Assets with an expected service life greater than one year are typically capitalized and depreciated over their expected lives.

[67] Determination of an appropriate approach to depreciation requires significant judgement to be exercised by an expert in the selection of a depreciation procedure, method, and technique. To calculate depreciation expense, at least one procedure, one method, and one technique must be selected:

- Procedures are employed to systematically allocate an asset or assets into subgroups.
- The depreciation method determines how the depreciation expense will be allocated over the life of the asset. The simplest and most common example is straight-line depreciation, which provides for an even charge each year.
- Finally, a technique is selected to determine the specific asset life to be used in the depreciation formula. The two techniques most frequently employed by depreciation experts are the whole life and remaining life techniques. The whole life technique calculates depreciation expense over the entire life of the asset from inception to retirement. The remaining life technique calculates depreciation expense over the expected remaining life. Generally speaking, both techniques should arrive at the same level of depreciation expense, all else being equal.

[68] Eastward owns significant assets, referred to as Plant, which were placed into service at different times. Due to the size and scope of the Company's asset base, Eastward tracks its assets in pools at a group level. This methodology is standard in the gas utility industry, as tracking a significant number of assets on an individual asset basis is not practical and is cost prohibitive. Eastward's asset groups are depreciated over a period that approximates their estimated remaining useful lifespan. A fraction of each asset group's original cost is treated as a depreciation expense each year until the asset investment and expected removal costs are fully recovered. Eastward is permitted to recover its prudently incurred costs, which include depreciation costs over the estimated useful life of the assets. Depreciation expenses are included in customer rates, and the cost of the assets are thereby recovered from customers over the expected useful life of the assets.

[69] Generally, depreciation expense is comprised of both a depreciation and net salvage component. Depreciation recovers the original cost of any investment added into the utility's rate base, with such recovery occurring over the expected useful life of the assets. Net salvage recovers the expected future costs to salvage and remove those assets, including any salvage proceeds, with such recovery also occurring over the expected useful life of the assets.

[70] In Eastward's previous general rate applications, the Board directed the Company to file depreciation studies. For the current application, Eastward engaged depreciation consultant Amanda Nori of Concentric Energy Advisors (Concentric) to conduct an independent study based on the Company's Plant in-service assets as at the

prior year end December 31, 2024. The Concentric report was included as Appendix 2 of the application.

[71] For most of Eastward's Plant accounts, the Concentric depreciation study, and the related proposed Eastward depreciation rates, are based on using the Equal Life Group (ELG) procedure, the straight-line method and the remaining life technique. For certain General Plant accounts, the proposed annual and accrued depreciation amounts are based on amortization accounting, which is discussed later in this decision. Eastward has used the ELG procedure in its prior depreciation studies, and its depreciation rates have been set accordingly. The ELG procedure calculates depreciation of individual assets or subgroups of assets within the same account that share the same or similar expected service life. This procedure relies on estimating retirement dispersion patterns and applying Iowa curves to model when assets are expected to retire, with depreciation rates reflecting those expected retirement patterns. Under ELG, assets that are expected to retire sooner are depreciated more quickly, while longer-lived assets are depreciated more slowly.

[72] Concentric also recommended that Eastward use a 0% net salvage in the calculation of depreciation rates. Concentric's proposed approach is contrary to a traditional depreciation study approach, where recovering net salvage costs embeds the recovery of those costs over the life of the assets based on the approved depreciation parameters. In response to Emrydia Consulting Corporation (Emrydia) IR-4, Eastward noted that it currently charges any cost of asset removal as an expense in the year of occurrence, and, as such, does not collect nor record net salvage for its assets.

[73] Finally, Eastward's application proposed a 25-year depreciation period beginning January 1, 2027, for its Rate Class 4.1 assets. Eastward stated that this appropriately balances the expected useful life of the underlying assets against potential intergenerational equity concerns. If a new customer uses these assets in the future, Eastward will reverse the additional depreciation so that the new customer's rates recover the remaining undepreciated capital costs of those assets.

[74] Dustin Madsen, CPA, CA, CPA (IL, USA), CDP, CRRA, of Emrydia was engaged by Board Counsel to provide expert analysis, recommendations and testimony about Eastward's depreciation practices, including reviewing and assessing Concentric's depreciation study and proposed depreciation rates. Hayitbay Mahmudov of InterGroup Consultants Ltd. was similarly engaged by the CA, as was Mr. Bowman by Michelin and Dalhousie.

[75] Mr. Madsen's evidence described what he believes to be the pros and cons of the ELG procedure as compared to those of the Average Life Group (ALG) procedure. ALG calculates depreciation using a single average service life for all assets within an account or asset group, rather than assigning different lives to individual assets or subgroups. Depreciation for the asset group is calculated using the straight-line method over the estimated average service life. The estimated average service life is typically derived from a combination of engineering judgement, historical experience, and the use of accepted Iowa survivor curves. Using ALG, each asset in the group is treated as contributing equally, on average, to the overall consumption of service value. The Board has summarized Mr. Madsen's "pros and cons" evidence as follows:

Procedure	Pros	Cons
Average Life Group (ALG)	Simplicity: Simple to apply and easy to understand.	Lower early-period cash flows: Depreciation expense is lower in earlier years compared to ELG, with higher depreciation occurring notionally in later years.
	Less potential volatility: Year-to-year changes in retirement data are less likely to materially affect depreciation expense unless they indicate a change in average service life.	Accuracy: Because ALG is less sensitive to survivor curve selection, incremental refinements to depreciation estimates are not as easily implemented.
Equal Life Group (ELG)	Accuracy: • Can appear more precise where asset lives are known and do not change. • May provide for more refined depreciation expense and increased accuracy, thereby allowing more variation in depreciation expense than charged under ALG.	Greater sensitivity and variability: Results are more heavily influenced by retirement data, which increases the risk that depreciation estimates deviate from actual retirement experience.
	Improved cashflow: Accelerates depreciation expense, improving near-term cash flow metrics and reducing reliance on near-term debt and equity financing.	Complexity: ELG is a complex procedure which can continue to be difficult for some parties to understand if they are unfamiliar with depreciation procedures, the derivation of Iowa curves, and the importance of retirement data.
		Potential incentive effects: Accelerated recovery may alter utility incentives, including the timing of capital replacement decisions.

[76] Mr. Madsen stated he would ordinarily recommend that Eastward change its depreciation procedure from ELG to ALG. However, he did not recommend a change to ALG in the current application for two primary reasons. First, Mr. Madsen recommended asset service life and survivor (Iowa) curve changes to several of the largest asset investment accounts for Eastward. These included use of a 60-R2.5 Iowa curve for Account 473.10 (plastic services) and Account 473.20 (steel services), and use of a 65-R3 Iowa curve for Account 475.20 (steel mains). Further, while Mr. Madsen did not oppose Eastward's use of amortization accounting for certain asset groups, he also recommended that Account 483.21 (software) should be increased to a 7-year life (7-SQ) and Account 483.40 (office furniture and equipment) should be increased to a 20-year life (20-SQ). Mr. Madsen noted that these changes would have a significant impact on Eastward's requested depreciation expense. He further stated that recommending these changes at the same time as a change to the ALG procedure would have a much larger impact on the total depreciation recovered in rates. Mr. Madsen believes it is best to phase in the impact of certain depreciation changes to ensure the change is gradual and moderate.

[77] Mr. Madsen's second reason for not recommending adoption of ALG at this time relates to Eastward's non-recovery of net salvage costs in depreciation rates. Mr. Madsen stated that it would be imprudent of him to recommend a reduction in the depreciation expense under the ALG procedure while also not recommending an increase in depreciation expense to recover net salvage costs from customers using the traditional method.

[78] But for these concerns, Mr. Madsen would have recommended that Eastward use the ALG procedure in establishing depreciation rates for the 2027 to 2029 test period. Accordingly, as opposed to transitioning to the ALG procedure at this time, Mr. Madsen recommended that Eastward continue with the ELG procedure along with his recommended changes to the average service lives and Iowa curves for certain asset groups. He further recommended that the Board direct Eastward to provide a fully compliant depreciation study calculated using the ALG procedure as part of Eastward's next general rate application, or at the time the next depreciation study is filed with the Board. He also recommended that the depreciation study also include recommendations for the recovery of net salvage through the traditional method of recovery net salvage.

[79] Mr. Mahmudov noted that Eastward currently adheres to U.S. GAAP standards for financial reporting purposes, but it may be required to transition to International Financial Reporting Standards (IFRS) in the future (discussed later in this decision). He also referenced Concentric's claim that ELG is a better fit than ALG for utilities that report under IFRS. Mr. Mahmudov argued that this claim is problematic. Instead, he suggested that both ELG and ALG procedures are permissible under IFRS; a contention which was also supported by Mr. Madsen. As such, Mr. Mahmudov recommended that the Board should consider the merits of the ELG vs ALG depreciation procedures for Eastward in the next depreciation study, once Eastward records sufficient retirements to conduct actuarial analyses on the assets installed in its distribution system. Similarly, Mr. Madsen recommended that the Board assign no weight to a potential change in accounting standards when determining the best depreciation procedure to use for Eastward either currently or in the future.

[80] Mr. Bowman concluded that Eastward has appropriately adopted group asset accounting for calculating depreciation, and that the development of its asset groups appears reasonable. However, he asserted that the ELG procedure is not well suited to Eastward's situation, with limited, if any, retirement history, and most assets in the early stages of their life curve. He also noted that even for mature utilities, like Enbridge Gas Inc. in Ontario, and Centra Gas Manitoba, regulators have rejected the ELG procedure when proposed by utilities for rate setting purposes. Mr. Bowman, therefore, recommended that Eastward revise its revenue requirement for 2027-2029 on the basis of adopting the ALG procedure for depreciation. He also recommended that in its next depreciation study, Eastward should consider including net salvage as a component of depreciation rates.

[81] As part of the settlement agreement, Eastward agreed to adopt the ALG depreciation procedure starting in 2027. Eastward also agreed to conduct an updated depreciation study for its next GRA, which would include an assessment of:

- Net salvage values;
- Asset account values;
- Asset service lives and related Iowa curves; and
- Amortization accounts.

Finally, Eastward agreed to ensure that its next depreciation study is IFRS compliant if the Company determines that it will be transitioning to IFRS reporting.

[82] The proposed depreciation rates in the Concentric study, using the ELG procedure, would result in Eastward having an annual depreciation expense of \$8.3 million, \$8.5 million and \$9.2 million in 2027, 2028 and 2029, respectively, when applied to depreciable Plant balances as of December 31, 2024. In Undertaking U-1, these

numbers were updated to \$8.82 million, \$9.04 million and \$9.72 million in 2027, 2028 and 2029, respectively, when updated for actuals up to December 31, 2025.

[83] However, as part of the settlement agreement, Eastward has agreed to move to the ALG methodology immediately at the start of the 2027 to 2029 test period. The methodological change to the ALG reduces the revenue requirement for all customer classes throughout the test period. As noted in Undertaking U-1, the depreciation rates resulting from consideration of the settlement agreement produce annual depreciation expense of \$7.39 million, \$7.56 million and \$8.15 million in 2027, 2028 and 2029, respectively, when updated for actuals up to December 31, 2025.

4.5.1 Findings

4.5.1.1 ELG vs. ALG

[84] Based on Eastward's response to Undertaking U-1, the settlement agreement revenue requirements associated with depreciation of Eastward's Plant in-service are approximately \$1.43 million, \$1.48 million and \$1.57 million lower in 2027, 2028 and 2029, respectively, than that calculated in Eastward's application (updated for actuals to December 31, 2025). This reduction results primarily from the change in use of ELG to ALG. The Board must determine whether these changes and the related reduction in depreciation expense are appropriate.

[85] Regardless of the depreciation procedure selected, the purpose of the exercise is to depreciate its prudently incurred original cost over the expected life of an asset. ELG seeks to align depreciation expense more closely with the forecast retirement pattern of assets as a means of trying to match cost recovery with estimated asset consumption. As such, Concentric has suggested that the ELG procedure is more accurate and theoretically preferred than ALG. Concentric noted, though, that the choice

between ELG and ALG primarily affects timing of depreciation expense recovery rather than total recovery over the life of the assets. In effect, while the amount charged in any one period may vary by virtue of the procedure selected, the total amount of depreciation recovered over the full life of the asset will not vary regardless of which procedure is used.

[86] Mr. Madsen, Mr. Mahmudov and Mr. Bowman argued that ALG provides for a more gradual, moderate and equitable recovery of depreciation. They also do not accept that Eastward's use of the ELG procedure inherently provides a better match between depreciation expense and loss in service value than the ALG. In particular, all three noted the absence of an actuarial analysis of asset service lives in Eastward's calculation of depreciation rates. Concentric's depreciation study noted that because Eastward's distribution system is still relatively young, not enough assets have been retired to conduct such analysis.

[87] Mr. Madsen, Mr. Mahmudov and Mr. Bowman each argued that this limitation is significant. The Board agrees. The proper application of the ELG procedure depends heavily on reliable estimates of retirement dispersion and the selection of appropriate lowa curves. This requires robust actuarial data that relies on a sufficiently large dataset of individual asset additions and retirements. Further, the data needs to be substantially complete across a meaningful portion of a utility's assets' life cycles, and the related historical information must be representative of future performance.

[88] In this context, given the relatively young age of Eastward's distribution system and lack of adequate asset retirement experience, the Board does not accept the "better matching" claim as an advantage of ELG. The claim is weakened by Eastward's limited actual asset retirement experience. In the absence of a solid foundation of actual

observed asset retirement data for Eastward, the Board believes that the ELG procedure could exacerbate the potential error in calculating the Company's depreciation expense. The Board, therefore, favors ALG's smoother allocation of depreciation. It provides a more prudent approximation of Eastward's asset service value consumption, primarily because it is less sensitive to the shape and timing of assumed retirement curves.

[89] Another issue that the Board considers important when deciding whether it is best for Eastward to use ELG or ALG is the related impact of each on intergenerational equity. Generally, the selection of a reasonable depreciation expense is heavily dependent on an assessment of equities between generations of customers to try and ensure, as best as possible, that the customers who use the assets pay for the assets.

[90] An argument for using the ELG procedure is that it is designed to allocate depreciation in a manner consistent with the statistical pattern of retirements within a life group, and that doing so promotes intergenerational equity by aligning cost recovery with the period over which assets provide service. However, as noted by Mr. Madsen, if this statistical pattern is not reflective of actual asset retirements, then current customers under the ELG procedure are more likely to overpay on existing assets in place than are future customers. In such circumstances, ELG will increase the volatility of depreciation expense and risk intergenerational inequity between customers.

[91] Given Eastward's limited actual asset retirement experience, the Board believes that the use of the ELG procedure by Eastward would increase this intergenerational inequity risk. Instead, the Board finds that the ALG procedure produces a more gradual and stable pattern of depreciation expense and related revenue

requirement. This, in turn, reduces the risk of intergenerational cost shifting compared to the use of ELG.

[92] Concentric, Mr. Madsen, Mr. Mahmudov and Mr. Bowman agree that ELG and ALG are both acceptable and appropriate procedures to determine depreciation expense. They also agree that both procedures require the use of significant judgement by depreciation experts. In addition, they have no dispute that although the timing of depreciation recovery varies, the total amount of depreciation recovered over the full life of an asset will be the same regardless of which procedure is used. They also agree that the ELG and ALG procedures are both compliant with IFRS reporting.

[93] Overall, the Board believes that the most appropriate depreciation procedure should set asset lives (and related depreciation expense) that best reflect the expected loss of service value of Eastward's assets over time while minimizing intergenerational inequity risks. The Board also recognizes, however, that no single depreciation procedure will be perfect, and no single procedure can ensure that forecast depreciation expense will be perfectly representative of actual depreciation expense. Further, consistent with the evidence in this proceeding, the Board notes that the advantages of one procedure correspond to the disadvantages of the other. The appropriate choice of depreciation procedure must also, therefore, balance these competing considerations. This effort to achieve an appropriate balance of interests can also be characterized as a matter between present and future customers.

[94] Considering the above, the Board finds that the ALG procedure is preferred in Eastward's circumstances. The Board believes the ALG procedure is an approach that better balances accuracy, gradualism, rate stability, and intergenerational equity. Use of

the ALG procedure also reduces depreciation expense and lowers the revenue requirement during the 2027-2029 test period. This will produce near-term rate relief for customers while preserving recovery of the same underlying Plant investment over time. As such, the Board accepts the settlement agreement terms for Eastward to adopt the ALG procedure and directs Eastward to do so beginning in 2027.

[95] During the hearing, Ms. Nori indicated that she would be willing to file her detailed ALG and ELG calculations as part of a compliance filing. The Board directs that this be done.

4.5.1.2 Net Salvage Costs

[96] Eastward currently charges any cost of asset removal as an expense in the year of occurrence. However, the traditional method of net salvage cost recovery embeds the recovery of these costs over the life of the assets based on the approved depreciation parameters. The net salvage parameter is generally expressed as either a positive or negative percentage based on the original cost of the asset. Concentric has assumed a 0% net salvage rate in its calculations. In effect, this approach assumes no net salvage is recovered in rates, as the inclusion of 0% assumes that on average it will cost nothing to retire and salvage the installed assets.

[97] In response to Emrydia IR-4, Concentric noted that Eastward does not yet have sufficient data available to conduct a net salvage study. Therefore, given the relatively young age of Eastward's system, Concentric stated that it supports Eastward's current approach of expensing net salvage costs in the year of occurrence. Nonetheless, Concentric indicated that as more data becomes available in future depreciation studies, the ability to accurately estimate net salvage ratios will be reviewed and net salvage may

be considered. Concentric also stated that it believes collecting net salvage costs as part of the depreciation study process is the most generationally equitable approach.

[98] In response to Emrydia IR-19, Eastward agreed with Concentric. Eastward stated that the cost of salvaging physical distribution assets will eventually need to be included in customer rates through depreciation of those assets. As such, Eastward acknowledged that these costs need to be included in a future depreciation study. Eastward also noted that in a future GRA proceeding, it will need to complete an assessment on how these costs should be recovered in customer rates.

[99] Both Mr. Madsen and Mr. Bowman asserted that the traditional method of recovering net salvage costs is the most technically correct and reasonable method of recovering net salvage costs from customers. The Board agrees. By linking the recovery of the cost of salvaging an asset to the recovery of the cost of the assets, the traditional method ensures that asset net salvage costs are recovered over the lives of the same assets. It also ensures that the customers who benefit from the currently installed assets pay to remove those assets. The Board finds this much more preferable to Eastward's current approach of expensing salvage costs in the year incurred, which results in current customers paying for a cost from which many generations of customers will benefit.

[100] As such, the Board accepts the settlement agreement terms related to net salvage values. The Board, therefore, directs Eastward to file a new depreciation study with its next GRA, which is to include an assessment of net salvage values for the related test period. This assessment is to include, but not be limited to, estimating net salvage costs outside of Eastward's own experience, such as comparisons to peers and engineering estimates of the cost of removal and remediation of the assets in service.

[101] The Board recognizes that inclusion of net salvage cost in depreciation rates could have a significant impact on overall customer rates. As such, the new depreciation study is also to include an assessment and related recommendations identifying how best to recover net salvage through the traditional method. This assessment is to include a review of the potential phase-in of net salvage costs over time as well any impact on OMA costs.

[102] The Board also directs that the depreciation study be IFRS compliant if Eastward determines it will be transitioning to IFRS reporting.

4.5.1.3 Estimated Average Asset Service Lives

[103] Key elements influencing the determination of depreciation expense are average asset service lives and survivor curves. Survivor curves (also referred to as Iowa curves) are a series of curves that have been developed to provide a statistical fit to the various lives of assets assessed in a depreciation study. These curves are broadly accepted and tested in North America and have been consistently accepted by regulators for determining reasonable depreciation expense. A survivor curve illustrates over time the percentage of assets that are expected to continue to be in service. Both Concentric and Mr. Madsen agree that the selection of estimated asset services lives and specific survivor curves is informed by a depreciation expert's judgement, comparisons with peer utility data, and discussions with utility company management and operations staff.

[104] As noted previously in this decision, the age of the Eastward's distribution system is still relatively young. Not enough retirements have occurred to conduct an actuarial analysis on the Utility's asset accounts. As such, Concentric developed its estimates of average asset service lives and Iowa curves based primarily on discussions with Eastward operations and management staff, a detailed peer review of Canadian

natural gas distribution systems, and Concentric's own understanding of the natural gas distribution industry.

[105] Given Eastward's limited actual asset retirement data, Mr. Madsen agreed that the approach used by Concentric to estimate Eastward's asset service lives and Iowa curves was appropriate. However, based on his own review of peer utility data, he recommended several changes to what was proposed by Concentric. As noted previously in this decision, these included changes to the recommended service lives and Iowa curves for plastic and steel services, steel mains, software, and office and furniture equipment accounts. Mr. Madsen also recommended that a further review of Eastward's metering stations account be completed in Eastward's next depreciation study.

[106] In its Rebuttal Evidence, Concentric disagreed with the changes recommended by Mr. Madsen. Nevertheless, Eastward did agree to review and assess Mr. Madsen's recommended account changes in the Utility's next depreciation study. The settlement agreement also includes provisions for such a review and assessment to be completed.

[107] The Board agrees that estimating asset service lives and selecting appropriate Iowa curves requires professional judgement, and experts can have differing opinions. The Board also understands the varying rationale put forward by both Concentric and Mr. Madsen as it relates to their respective recommendations. The Board believes that there are merits to both sets of recommendations. However, the Board highlights the reluctance of Mr. Madsen to recommend that Eastward switch to the ALG procedure at the same time as implementing his recommended changes to asset service lives and Iowa curves. Mr. Madsen stated that recommending a change to the ALG

procedure at the same time as adopting his recommended asset service life and Iowa curve changes would have a much larger impact on the total depreciation recovered in rates. He, therefore, suggested that it is best to phase in the impact of certain depreciation changes to ensure the change is gradual and moderate.

[108] Given that the Board has directed Eastward to adopt the ALG procedure starting in 2027, the Board considers Mr. Madsen's suggestion to be reasonable. Therefore, the Board finds that it would not be prudent to adopt Mr. Madsen's recommended asset service life and Iowa curve changes contemporaneously with the directed change to the ALG procedure. However, the Board believes that Mr. Madsen's recommendations should be investigated further. As such, the Board finds that the terms put forward in the settlement agreement are acceptable. The Board, therefore, directs that Eastward's next depreciation study provide a comprehensive assessment of asset service life and Iowa curves, including the changes suggested by Mr. Madsen.

[109] In addition, the Board directs that Eastward's next depreciation study include the following:

- Detailed management notes for each account;
- All analysis and studies performed by management for each asset to confirm the expected life; and
- The peer analysis relied upon by the Company in an Excel file.

4.5.1.4 Class 4.1 Assets

[110] The Board finds that Eastward's proposal to change to a 25-year depreciation period for its Class 4.1 assets is reasonable and provides a suitable balance between expected service life and intergenerational equity concerns. Further, no party to

this proceeding objected to the change. The Board, therefore, approves Eastward's proposed change.

4.5.2 Amortization Accounting for General Plant Assets

[111] Eastward has proposed the use of amortization accounting for certain General Plant accounts that represent numerous units of property, but a small portion of its total depreciable Plant in service. Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Amortization accounting is typically employed for accounts with a smaller investment balance relative to larger accounts, and where there are numerous assets without distinguishable life characteristics, such as laptops.

[112] In amortization accounting, the cost of an asset is allocated over a decided time frame, typically a period consistent with its expected service life. The asset is retired and removed from the accounting books once it has been fully amortized, regardless of whether it is rendering service.

[113] The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in Eastward's depreciation study are based on Concentric's judgement, which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

[114] Eastward proposed the use of amortization accounting for the following General Plant accounts:

- Account 483.10 Computer Equipment (5-year amortization period);

- Account 483.21 Software (5-year amortization period);
- Account 483.40 Office Furniture and Equipment (15-year amortization period);
- Account 486.00 Tools and Work Equipment (15-year amortization period); and
- Account 496.00 Franchise (25-year amortization period).

[115] Historically, the assets to be subject to amortization accounting have been depreciated using the straight-line method and ELG procedure, using the remaining life technique. However, with the exception of Account 496.00, Concentric recommended amortizing the investment using an industry-wide approved methodology of a whole-life rate effective January 1, 2027. This whole-life rate simply calculates the annual accrual rate for a given account as $1/\text{Average Life}$. Concentric noted that moving these accounts to a whole life approach in the short term will allow for rate stability in the long term.

[116] Since the whole life rate does not include any true-up for the historical over or under accrual in the accumulated depreciation reserve, it is necessary for Concentric to calculate the true-up separately for these accounts. A surplus of booked accumulated depreciation currently exists when compared to the calculated accrued depreciation, which can be expected using the previous procedures. As part of the recommendation to move to use of a whole life rate, Concentric recommended recalculating the true-up as of December 31, 2026, and refunding the surplus of accumulated depreciation over Eastward's upcoming General Rate Application period of three years. This has been incorporated into the rates proposed in Eastward's application.

[117] In response to NSEB IR-46, Eastward confirmed that the proposed change to amortization accounting for the above noted accounts would have an immaterial impact on customer rates. In addition, Mr. Madsen's evidence noted that the use of amortization accounting for such accounts is common for utilities.

4.5.2.1 Findings

[118] The Board notes that the asset groups Eastward has proposed be subject to amortization accounting consist of numerous units of property, often of modest original individual cost, particularly when compared with units in other asset groups. Property of this type tends to have a relatively short useful life. Over time, as the reserve imbalance is trued-up, the use of amortization accounting for these accounts should result in much less accounting effort to track these numerous, low unit-cost assets. This should result in lower administrative overhead costs without any material reduction in accounting accuracy. As such, the Board finds that the proposed amortization accounting for these accounts is a prudent way to manage cost recovery.

[119] The Board, therefore, approves the use of amortization accounting for the five General Plant accounts as proposed.

4.5.3 Capital Expenditures and Plant Continuity

[120] Recovery of Eastward's proposed capital expenditures from customers is through depreciation rates. In its application, Eastward estimated continued expansion of its distribution system to support the forecast growth of customer base during the 2027-2029 test period. The forecast includes total capital expenditures of \$103 million over the test period, including \$14.3 million of capitalized overhead.

[121] Sustained capital investment in Eastward's distribution network and other required capital investments is necessary to ensure safe, reliable service for customers. Planned spending is expected to result in a net increase of approximately \$81.7 million in traditional net plant in service (the largest component of rate base), from \$252.3 million at the end of 2026 to \$334.0 million at the end of 2029 (an increase of over 32%). Eastward's application forecasts annual capital expenditures of \$17.8 million, \$31.8

million and \$53.4 million in 2027, 2028 and 2029, respectively. The majority of the capital spending for the test period is on Mains and Services, at \$76.2 million.

[122] As noted previously in this decision, Eastward anticipates three large interconnections to its system in 2030, 2031 and 2033. These include a potential conversion of NS Power's Trenton Generating Station to natural gas from coal, as well as two proposed fast-acting natural gas-fired generating plants that are working their way through the IESO NS procurement process. As such, Eastward has allocated capital in 2029 to account for a portion of these potential infrastructure requirements.

[123] Further, as part of Eastward's capital planning process, a steel pipeline construction project referred to as the Bedford Loop has been identified with forecast capital spending during the 2027-2029 test period. This project, if approved by the Board in a future proceeding, would include the construction of approximately 12 km of steel pipeline in multiple phases that extends from Burnside, Dartmouth to the existing Larry Uteck District Regulating Station on the Bedford Highway. The pipeline project is intended to improve system redundancy by providing a secondary redundant natural gas feed to the large Halifax/Bedford distribution systems that are currently solely fed through the Halifax Harbour Crossing pipeline. In addition to system redundancy, the project would allow the opportunity to serve areas of Bedford and Sackville that do not currently have natural gas access. It is anticipated that a separate approval application for this project will be filed with the Board in advance of construction starting in 2028.

[124] Eastward also forecast capital spending in 2029 associated with the "energy evolution" project. During the hearing, Eastward explained that this capital is not assigned to any particular project but is instead earmarked for potential decarbonization related

capital spending. This spending could be related to capital projects associated with hydrogen blending and the use of renewable natural gas.

[125] The settlement agreement proposed no changes to Eastward's anticipated capital expenditures over the 2027-2029 test period.

4.5.3.1 Findings

[126] Cathcart reviewed Eastward's proposed capital expenditure forecasts. Based on its review, Cathcart recommended that the Board closely scrutinize Eastward's capital spending plans, which results in a net increase in Eastward's traditional rate base of approximately 30%, while customer additions are projected at only 11%. Cathcart noted that this raises concerns regarding cost causation, prudence, and the appropriate allocation of costs between customer classes. Cathcart noted particular concern related to the significant weighting of expenditures toward major projects such as the Bedford Loop and the potential interconnection projects, much of which appears directed at system redundancy and long-term expansion capacity rather than immediate customer-driven growth. Cathcart also recommended that approval of further capital additions should be tied to demonstrable progress toward Eastward's operational and financial maturity.

[127] The Board notes that Eastward files regular reports with the Board on its proposed capital spending. These include annual Means Feasibility Test (MFT) compliance reports, and annual Permit to Construct applications. Eastward is also required to file project specific capital approval applications for projects that are expected to exceed \$250,000 in capital spending. The Board understands Cathcart's concerns and will monitor, and address as may be required, the issues raised by Cathcart as Eastward files its reports and capital approval applications with the Board.

[128] The Board also notes that during the hearing, Eastward confirmed that there are no revenue requirements in the 2027-2029 test period rates associated with the potential interconnections of the Trenton generating station and IESO NS gas turbines. Nor are there any revenue requirements in test period rates associated with the “energy evolution” project. As for the Beford Loop project, Eastward confirmed that depreciation and related rate treatment commence only when the associated assets are placed into service.

[129] Cathcart also recommended that the Board require Eastward to file detailed capital project-level breakdowns by year, category, and by the driver of the capital spend. Cathcart suggested that the reporting should also include in-service schedules before determining the prudence of these additions. Driver categories to report on capital spending should include: a) Growth – necessary for customer additions, b) Replacement or Maintenance – to maintain the existing system for reliability, and c) System-level Reliability/Redundancy – for large-scale reliability and redundancy for risk reduction.

[130] In its Rebuttal Evidence, Eastward addressed this recommendation by proposing that annual capital reports can be filed with the Board for the Permits to Construct in a manner similar to reporting for MFT projects, as part of the annual Financial Compliance report. Eastward said it would report on the capital spend and forecasted remaining spend for the Permits to Construct currently under construction and then would provide a five-year true-up to feasibility results, where applicable. This proposal was incorporated into the settlement agreement.

[131] The Board accepts this element of the settlement agreement and directs Eastward to file such annual reports. The Board also directs Eastward to include a clear

roadmap with measurable milestones for full cost recovery within its annual financial compliance report.

[132] Finally, in Undertaking U-8, Eastward reconciled the Bedford Loop capital project assets in Table 5.1 of the Application, and explained that those assets had been misclassified in the Application and were reclassified mainly into Steel Mains in the Undertaking. The restated table also reflects actuals to December 31, 2025. The Board directs Eastward to incorporate this updated information into its compliance filing.

4.6 Accounting and Capitalization Policies

4.6.1 Accounting policies

[133] Eastward currently prepares its financial statements using U.S. Generally Accepted Accounting Principles. In 2008, the Canadian Accounting Standards Board announced that for fiscal years beginning on or after January 1, 2011, all publicly accountable entities would be required to transition to International Financial Reporting Standards. Eastward has been given exemptive relief from Canadian Securities regulators and has remained on U.S. Generally Accepted Accounting Principles. Eastward noted in response to NSEB IR-73 that its exemptive relief had been extended until the earliest of the following: (i) January 1, 2032; (ii) if the filer ceases to have rate-regulated activities, the first day of the filer's financial year that commences after the filer ceases to have rate-regulated activities; and (iii) the first day of the filer's financial year that commences on or following the later of (a) the effective date prescribed by the International Accounting Standards Board for the mandatory rate-regulated standard; and (b) four years after the International Accounting Standards Board publishes the final version of a mandatory rate-regulated standard.

[134] In May 2026, after the filing of Eastward's application, the International Accounting Standards Board issued IFRS 20 Regulatory Assets and Regulatory Liabilities, the new standard developed to address the financial reporting of rate-regulated entities. IFRS 20 is effective for annual periods beginning on or after 1 January 2029, with early application permitted. Eastward's current exemptive relief now expires as of January 1, 2031. Eastward must therefore either obtain permanent exemptive relief or transition to International Financial Reporting Standards by that date.

[135] During the hearing, Ashley MacDonald, Eastward's Vice President of Finance, noted that the Company has committed to reporting to the Board in early 2027 about the decision of its parent company, TriSummit Utility Holdings (Nova Scotia) Inc. (TriSummit Utilities), regarding International Financial Reporting Standards transition. Eastward further confirmed that if the decision of TriSummit Utilities is to transition to International Financial Reporting Standards, the depreciation study provided in its next general rate application will be compliant with these standards. Eastward also noted that it reports on the status of a transition to International Financial Reporting Standards in its annual financial compliance report and that it will continue to do so.

4.6.2 Capitalization Policy

[136] Eastward capitalizes its Operating Maintenance and Administrative costs based on a prescribed formula for departmental expenditures. Eastward's capitalization policy has been in effect since 2012. The capitalization rates forecast in the test years are consistent with Eastward's existing capitalization rates and policy.

[137] In Eastward's previous general rate application, Board Counsel consultants Jason Hails and Roger Cathcart expressed concerns about Eastward's capitalization policy. They recommended that Eastward use the "capital module" of the software

package it currently uses for its time tracking for payroll purposes to provide a more accurate basis for capitalizing OMA costs. They also recommended Eastward investigate the creation of more suitable overhead allocation factors to account for relevant capital activities and that it explore the implementation of a time-carding system to track capital activities or employ a manual system.

[138] In the current application, and in further detail in response to NSEB IR-44, Eastward stated that there would be significant cost and resource requirements to accomplish these recommendations. It further noted that if Eastward transitions to International Financial Reporting Standards by 2031, it is likely that changes would be required at that time. It states it would be prudent to await the decision on International Financial Reporting Standards before investing time and money into the process and system changes recommended by Mr. Hails and Mr. Cathcart.

4.6.2.1 Findings

[139] The Board accepts Eastward's suggested approach to International Financial Reporting Standards transition reporting; consisting of a report in early 2027 and continued reporting through its annual financial compliance report. Further, the settlement agreement states that Eastward will "report for the next GRA on the IFRS transition analysis, related IT system requirements, including time carding and capital modules, the review of Eastward's capitalization policy against IAS 16, and an IFRS-compliant depreciation study if an IFRS transition is confirmed...". The Board further accepts that any changes to Eastward's capitalization policy, or systems and time tracking, should be evaluated at the same time as the decision regarding a transition to International Financial Reporting Standards. The Board directs Eastward to provide the agreed upon reporting.

4.7 Capital Structure (Rate of Return and Debt/Equity Ratio)

[140] Eastward's existing rates are set based on a current capital structure that includes 55% debt and 45% equity, with an approved return on equity (ROE) of 10.65%. In this matter, Eastward filed a cost of capital report prepared by James M. Coyne, Senior Vice-President, and John Trogonoski of Concentric Energy Advisors Inc. (Concentric). The report recommended an ROE for Eastward between 10.65% and 11.4%. In its application, Eastward requested an increase to its ROE from 10.65% to 10.80%. Under the settlement agreement, the parties agreed to an ROE of 10.70%.

[141] Eastward seeks to maintain its debt-to-equity ratio at 55% debt and 45% equity, which the parties agreed to in the settlement agreement.

4.7.1 The Fair Return Requirement

[142] A fair return is fundamental to ensuring a utility's ongoing financial stability. Because Eastward must secure capital to undertake necessary investments, it requires a return sufficient to attract and retain investors. If the approved return is set below levels commensurate with the utility's risk, investor confidence may erode.

[143] In approving and fixing rates, tolls and charges for Eastward, s. 22(1) of the *Gas Distribution Act* requires that the Board determine "just and reasonable rates, tolls or charges for the delivery of gas by a gas delivery system, including related services." Under s. 22(3), the Board "shall give due regard" to the "(c) effectiveness in yielding total revenue requirements under the just and reasonable return standard", among other criteria, and giving appropriate weight to each of the criteria relative to the others. In the context of Eastward Energy, which operates as a natural monopoly in the distribution of natural gas in the province, the Board considers the "just and reasonable return standard" in setting Eastward's total revenue requirement.

[144] The “just and reasonable return standard” is one that is more commonly referred to in the regulatory context of setting a utility’s return as the “fair return requirement”. A fair return is fundamental to ensuring a utility’s ongoing financial stability. There is a well-recognized and long-standing legal standard the Board must follow when approving a utility’s return on its invested capital. The test for this standard was described by the Supreme Court of Canada almost a century ago and is still recognized as the authoritative description of the standard:

18 The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise. ...

[*Northwestern Utilities Ltd. v Edmonton (City)*, [1929] SCR 186]

[145] In *Ontario (Energy Board) v Ontario Power Generation Inc.*, 2015 SCC 44, the Court elaborated on the meaning of the fair return requirement:

[16] This means that the utility must, over the long run, be given the opportunity to recover, through the rates it is permitted to charge, its operating and capital costs ("capital costs" in this sense refers to all costs associated with the utility's invested capital). This case is concerned primarily with operating costs. If recovery of operating costs is not permitted, the utility will not earn its cost of capital, which represents the amount investors require by way of a return on their investment in order to justify an investment in the utility. The required return is one that is equivalent to what they could earn from an investment of comparable risk. Over the long run, unless a regulated utility is allowed to earn its cost of capital, further investment will be discouraged and it will be unable to expand its operations or even maintain existing ones. This will harm not only its shareholders, but also its customers: *TransCanada Pipelines Ltd. v. Canada (National Energy Board)*, 2004 FCA 149, 319 N.R. 171 (F.C.A.). [Emphasis added]

[146] The elements of the fair return requirement have often been canvassed by Courts and utility regulators across Canada. A more detailed review of the fair return requirement was recently discussed by the Nova Scotia Energy Board in its *NS Power 2026-2027 General Rate Application* Decision, 2026 NSEB 8, at paras. 442 – 451. The

Board adopts and repeats that review of the fair return requirement and will apply it for the purposes of Eastward's application for its proposed return on equity.

4.7.2 Overview of Cost of Capital Evidence

[147] The assessment of an appropriate return on equity typically relies on the application of several established financial models. In practice, these models are applied with reference to prevailing capital market conditions. The results are commonly evaluated across multiple models to assess reasonableness, consistency and overall robustness.

4.7.2.1 Return on Equity

[148] The ROE is estimated using one or more techniques to quantify the expectation of the utility's investors regarding required equity returns. Eastward considered the results of several models in developing a ROE recommendation, namely the Capital Asset Pricing Model; Discounted Cash Flow model; and Risk Premium Model. These established approaches assess prevailing capital market conditions and use multiple analytical models to ensure the consistency and robustness of the conclusions.

4.7.2.1.1 Return on Equity Models

[149] The Capital Asset Pricing Model (CAPM) is a financial framework that estimates the relationship between systematic risk and the expected return on an investment. The main components of the CAPM model include the risk-free rate of return, the market risk premium and company betas.

[150] The Discounted Cash Flow (DCF) model estimates the rate of return that an investor requires to invest in a company using the current dividend yield plus the forecasted growth rate of dividends.

[151] The Risk Premium model may be based on historical differences in the return between bonds and equity or the expected bond-equity return spread. The Risk Premium model accounts for equity holding more risk than debt, because an equity investor bears the risk associated with ownership and therefore requires a higher return than a bondholder. The riskier the company, the greater the difference between these returns. The standard equation for the Risk Premium calculates the ROE as the sum of the yield on long-term bonds and the equity risk premium or the difference between the bond and equity returns.

4.7.3 Modeling the Return on Equity

[152] Concentric noted that an assessment of the appropriate return for Eastward depends on the fundamental legal and regulatory principle that a utility must be given a reasonable opportunity to earn a fair return on its invested capital.

[153] Concentric provided an overview of the macroeconomic conditions, central bank policies and bond yields in Canada and the United States. Concentric regards the Canadian and U.S. markets as tightly integrated economies and that there are no fundamental dissimilarities between the two countries that would lead an investor to expect different returns for a group of comparable risk utilities in either country.

[154] Concentric developed three proxy groups for the ROE analysis that were established based on companies that are publicly traded and comparable to Eastward in fundamental business and financial respects. The first proxy group was comprised of publicly traded, regulated Canadian electric and natural gas utility companies. The second proxy group was comprised of U.S. gas distribution utility companies. The third proxy group was a combined North American Gas Proxy Group, consisting of four Canadian utility companies with significant natural gas operations and six U.S. gas

distribution facilities. It is Concentric's view that assessing a North American proxy group of companies is the most reliable for determining the cost of capital and is consistent with how investors see the market.

[155] Concentric estimated the required equity returns for the proxy group using three standard methodologies: CAPM, DCF and Risk Premium. In Appendix 3 to the application, Concentric stated that "it is common practice for Canadian regulators to approve an adjustment for flotation costs and financing flexibility, with 50 basis points being the norm" and explained:

The adjustment for flotation costs compensates the equity holder for costs associated with the sale of new issues of common equity. These costs include out-of-pocket expenditures for preparation, filing, underwriting, as well as a discount to the share price, and other costs of issuance of common equity. An adjustment is also made to provide for financial flexibility such that there is adequate cushion to raise equity in challenging capital market conditions.

[Exhibit-1, p 314]

[156] During the hearing, Concentric was asked to provide the CAPM model results using only the average historical market risk premiums for Canada and U.S. as reported by Kroll, 6.53%, following the approach used in the recent NS Power general rate application, in Undertaking U-9. In the discussion that follows, references to results from Concentric's analysis are to the update it provided in Undertaking U-9 using the analysis as generally described in its original report (Exhibit E-1, Appendix 3 – Cost of Capital Report) for its North American proxy group.

[157] As previously noted, the variables used in the CAPM are the risk-free rate of return, the market risk premium (MRP) and a beta coefficient. Concentric used Kroll's Canadian and U.S. market risk premium from 1919 to 2024 for its MRP. For its risk-free rate of return, the average long-term Consensus Forecast of 10-year government bond yields for 2027-2029 was applied. Concentric used the average of the betas reported by

Bloomberg and Value Line. A flotation cost of 50 basis points was added to calculation to determine CAPM results of 9.24% for the North American proxy group.

[158] The premise underlying the DCF model is that investors value a given investment according to the present value of its expected cash flow over time. Eastward in its application presented the results of both the constant growth DCF model and the multi-stage DCF model. However, Concentric relies on the results of the multi-stage model. It submitted that the multi-stage version of the DCF produces more conservative return estimates. The model used three stages of dividend growth: near-term, long-term and transitional. The near-term growth used the average of Value Line, Zacks, S&P Capital IQ Pro and Seeking Alpha forecasts for years one to five multiplied by the dividend yield. The long-term growth rate applied nominal gross domestic product, which is comprised of gross domestic product growth and inflation of 1.8% and 2% for Canada and 1.9% and 2.3% for the U.S., as forecasted for the years 2031-2035. The transitional stage growth prorates the near-term growth to meet the long-term growth over years six to 10.

[159] Applying this model to its proxy groups and adjusting for flotation costs, Concentric determined that a return on equity of 9.28% was appropriate under its DCF analysis.

[160] Concentric used two separate Risk Premium analyses. For the U.S. proxies the analysis is based on authorized ROEs for gas distribution companies since 1992. For Canada, Concentric used authorized ROEs for Canadian gas and electric utilities since 1994. It conducted a regression analysis where the risk premium is the difference between authorized ROEs and the 30-Year Treasury Yield. The results are shown in

Figure 26 of Exhibit E-1, p. 318. The U.S. risk premium analysis average equity risk premium is 5.85%. Concentric's preferred U.S. result of 10.39% was based on the Blue-Chip Long Term 2027-2031 bond yield forecasts.

[161] The Canadian risk premium analysis showed that the average equity risk premium in Canada was 5.83%. The results of the Canadian risk premium analysis are shown in Figure 28, Exhibit E-1, p. 320. Concentric preferred the 9.52% result, which was based on the 2026-2030 Forecast 30-Year Government of Canada bond yield plus the historical spread between Canadian 10- and 30-year bonds, because it presents a forward-looking view on the cost of capital. Concentric averaged the Canadian and U.S. results to arrive at 9.96% as a North American risk premium.

[162] Concentric placed equal weight on the North American results from the three models to arrive at an average ROE of 9.49%.

[163] In consideration of Eastward's business and financial risks, the gas industry's risks and to reflect that Eastward Energy is a small-developing utility, Concentric applied a risk adjustment of 75 and 150 basis points to its North American gas proxy group three-model average. This adjustment increased the three-model average of 9.49% to range from 10.25% to 11.0%. Concentric's final return on equity results are summarized in the table below:

Concentric	CAPM	DCF	Risk Premium
Canada	8.51%	9.23%	9.52%
US	9.56%	9.33%	10.39%
North American	9.24%	9.28%	9.96%
Mean	9.49%		
Risk Adjustment	75 to 150 basis points		
ROE	10.25% - 11.0%		

[164] Eastward agreed with Concentric that the recommended range for the Company's ROE is reasonable based on its risk profile. Eastward requested an ROE of 10.8%.

[165] Dr. Sean Cleary, CFA, Professor of Finance, who filed evidence as a cost of capital expert on behalf of Board Counsel, was the only other expert to address Eastward's required return on equity. In his evidence he claimed that both of Concentric's DCF and CAPM analysis are flawed by the heavy reliance on data from U.S. utilities, which he cites as having significantly higher business risk relative to Canadian utilities. He stated that the main difference in his recommendation versus that of Concentric's is attributable to the significant differences in their respective ROE estimates.

[166] Dr. Cleary, in his evidence, further stated that he is confident his CAPM estimate for Canadian utilities as of April 5, 2026, of 6.96% is accurate. He made several adjustments to address the Board's concerns that were outlined in its March 2026 *NS Power GRA* Decision regarding his CAPM model in that matter. He modestly increased the variables. Specifically, he increased: the Risk-Free Rate of 3.85% to 3.9%, the Market Risk Premium from 5.6% to 6.0%; and the beta from 0.43 for 0.45. After applying an adjustment of 50 basis points for flotation, Dr. Cleary arrived at a CAPM estimate of 6.96%.

[167] To estimate a DCF return, Dr. Cleary used the single stage Dividend Discount methodology. He calculated the average and median seven-year dividend yields and payouts for five Canadian proxy electric and gas companies. He estimated a sustainable growth rate using the seven-year average ROEs for the same proxy companies against their seven-year average payouts to arrive at a sustainable average

growth rate of 1.68%. The same method was used to arrive at the median sustainable growth rate of 1.42. A summary of the inputs was provided in Table 10 of his evidence in Exhibit E-21, p. 74.

[168] Dr. Cleary then estimated the average of the mean and the median DCF estimates to arrive at a final DCF return on equity of 6.25%. He then added flotation of 50 basis points to recommend a DCF estimate of 6.75%. Dr. Cleary regarded his DCF estimate as high given that regulated utilities are less risky than the average company.

[169] A Bond Yield Plus Risk Premium (BYPRP) model was used as the third estimate of ROE in Dr. Cleary's evidence. He explained that the BYPRP adds a risk premium to the yield on a firm's publicly traded long-term bonds. While sharing a name with the variable used in the CAPM, this is a separate model that is the predecessor to the CAPM. To arrive at an ROE through this method, the bond yield was added to a company's risk premium. Using data for his five proxy Canadian utilities, as of March 31, 2026, the mid-point yield on bonds outstanding was 5.03%. A risk premium of 2.5% was applied, as Dr. Cleary regarded this to accurately reflect the low-risk nature of Canadian regulated utilities. The two variables were summed, and a flotation of 50 basis points was applied to arrive at 8.0%.

[170] Dr. Cleary stated that the base-case cost of equity estimate for Canadian utilities is a more reasonable 7.24%. In his opinion, this estimate represented an equally weighted average of his CAPM estimate of 6.96%, DCF estimate of 6.75%, and BYPRP approach estimate of 8.0%. Dr. Cleary suggested that his estimated cost of equity using Canadian regulated utilities is slightly below his 7.5% estimated required market return.

Dr. Cleary then made a risk adjustment of 150 basis points and arrived at 8.74% as his recommended ROE for Eastward.

Cleary	CAPM	DCF	Risk Premium
ROE with Flotation	6.96%	6.75%	8.00%
Mean	7.24%		
Risk Adjustment	150 basis points		
ROE	8.74%		

4.7.3.1 Capital Structure

[171] Eastward seeks to maintain its Equity Ratio at 45%, and its Cost of Debt on the historical debt balance and for forecasting and rate making purposes at 6.95% over the test period (2027-2029). Eastward takes the position that these “cost of capital parameters provide an equitable position for both customers and investors and that they are appropriate given the substantive risks the Company is facing.” [Exhibit E-1, p. 104]

[172] Dr. Cleary supported Eastward’s request to maintain its 45% equity ratio. He agreed that Eastward possesses greater risk than the typical Canadian low-risk regulated operating utility, and therefore providing additional equity thickness is warranted.

4.7.3.2 Party Submissions

[173] Eastward in its closing submissions addressed the settlement agreement which included a consensus on several issues, including rate design and class impacts, return on equity and cost of debt as follows:

- **ROE:** ROE is 10.7% with an equity thickness of 45%;
- **Cost of debt:** Eastward will maintain the existing long-term cost of debt at 6.95%, and the cost of any future debt will be value-weighted with existing outstanding debt to determine Eastward’s overall long-term cost of debt;

[174] Dr. Cleary in his Opening Statement commented on the settlement agreement and stated:

The settlement agreement that was reached by Eastward Energy and customer representatives echoes my long-term debt recommendations of 6.95% for existing long-term debt and value weighting the cost of additional long-term debt raised in the future. The settlement agreement further recommends a continuation of EE's allowed equity ratio of 45%, combined with an ROE of 10.7% (which is up from the previous of 10.65%, but is below EE's requested rate of 10.8%). While remaining confident in my market-based ROE and equity ratio recommendations, I acknowledge that reaching a settlement agreement does involve trade-offs that the Board must take into consideration.

[Exhibit E-45]

[175] In its Opening Statement NSDOE said that the Province is supportive of the continued operation and development of natural gas distribution in Nova Scotia.

[176] The Consumer Advocate in his closing submissions submitted that the settlement agreement is in the best interests of residential customers and provides a just and reasonable resolution of this matter. He considered that the settlement was the result of compromise on behalf of all parties, and results in a significantly improved application from the perspective of the RSC, with not only a reduced ROE, but also a reduced cap for the deferral recovery rider, all of which will help promote customer affordability and still allow Eastward to meet its revenue requirement. The CA stated that the resulting rates for residential customers are just and reasonable in the context of this present Application, and it supports their adoption by the Board.

[177] Michelin/Dalhousie in their closing submissions stated that the settlement agreement achieves rate reductions for all customer classes as a result of shifting the depreciation methodology to Average Service Life, along with a reduced rider cap for all customer classes and a slightly reduced ROE. Michelin/Dalhousie argued that the settlement agreement is reasonable, balanced, and in the public interest, and should be approved by this Board as filed.

4.7.4 Findings

[178] It is well established that investors in regulated utilities are entitled to a fair return that is comparable to that of investments with similar risk, stability and attractiveness. Failing to provide a fair return could discourage investment and undermine the utility's ability to maintain and develop its operations to the detriment of its shareholders and customers. The Board summarized the factors in the recent NS Power GRA matter:

[512] Factors that may be appropriately taken into account in setting a fair return are comparable returns on similar investments, the level of return needed to attract capital and the financial integrity of the utility. Factors that other cases have determined are not appropriate to consider include the impact of a fair return on rates or as a tool for balancing other interests between the utility and its customers, such as affordability or reliability. That is not to say these factors are irrelevant, just that they are not properly taken into account in setting the allowed return. There are other regulatory tools that can be used to lessen near term rate impacts and affordability issues, but they generally come at a higher long-term cost and may shift costs to other or future customers who did not receive the benefit of the service to which the costs relate.

[2026 NSEB 8, para. 512]

[179] The settlement agreement reached with the intervenors representing most of Eastward's customer representatives resulted in the requested ROE decreasing from the proposed 10.8% to 10.7% (the current approved ROE is 10.65%). In Dr. Cleary's Opening Statement he noted the alignment between the settlement agreement and his long-term debt recommendations for existing long-term debt and value weighting the cost of additional long-term debt raised in the future. He acknowledged that the ROE in the settlement agreement was higher than his recommendation but accepts that reaching agreements such as these requires trade offs.

[180] Overall, the Board finds the proposed ROE under the settlement agreement to be reasonable in the circumstances. There was no proposed change to Eastward's cost of debt, 6.95%, for existing debt, or the debt-to-equity ratio of 55%/45%. In

accordance with the settlement agreement, the Board approves an ROE of 10.7% for the 2027-2029 test period and capital structure of 55% debt/45% equity.

4.8 Cost of Debt

[181] Eastward requested approval for a cost of debt of 6.95% on existing debt. The existing long-term debt has a locked in interest rate of 6.95%. TriSummit Utilities provided Eastward with a shareholder loan in the cumulative amount of \$184 million at this interest rate. Of that amount, \$33.5 million matures on January 1, 2029, which is the start of the third test year. The remainder of this debt matures on January 1, 2031 (\$34 million), January 1, 2034 (\$73 million), and January 1, 2044 (\$43.7 million). Therefore, using a cost of debt of 6.95% for this existing debt for ratemaking purposes is fully supported and no one opposed this.

[182] Going forward, Eastward will be required to obtain new financing, and refinancing of the \$33.5 million maturing on January 1, 2029, on a stand-alone basis. This decision was taken by TriSummit Utilities and that is outside the Board's regulatory control. For refinancing and new debt, Eastward proposes to use an indicative rate at the time of financing determined by the 30-year Government of Canada Bond Benchmark plus Eastward's credit spread, as determined by a major Canadian bank. Eastward said that any difference between the forecasted debt rate for the test years and the actual rate for new debt issuances or refinancings, as well as differences in forecasted and actual borrowing levels, would be captured within Eastward's existing RDA deferral account.

[183] Dr. Cleary raised a concern about the weighting when calculating the actual cost of debt. In its Rebuttal Evidence, Eastward agreed with Dr. Cleary as follows:

Eastward agrees that any future debt will be value-weighted with existing outstanding debt to determine the overall long-term cost of debt. Eastward also agrees that a new debt agreement will be issued between TSU and Eastward based on the market rate at the time

of any debt refinancing or new issuances. This market rate, as per the debt agreement, will be used in the calculation for overall long-term debt as detailed by Dr. Cleary in response to EEI-IR-1(b).

[Exhibit E-32, pp.23-24]

[184] Dr. Cleary's response to EEI-IR-1(b) provided a sample calculation of value weighting new debt with the 6.95% rate on existing debt:

(b) Please refer to the calculations below, which assumes EE raises an additional \$15.6 million in new debt at a cost of 6.8%, which is combined with the existing long-term debt of \$184.4 million (at a cost of 6.95%) provided in Table 10.1 of EE's 2026 Rate Application, resulting in total long-term debt of \$200m:

$$\text{New cost of long-term debt for EE} = (184.4/200) \times 6.95\% + (15.6/200) \times 6.8\% = 6.938\%$$

[Exhibit E-22, p.3]

[185] The Settlement agreement incorporates the cost of debt as set out in the Application. Dr. Cleary's recommendations relate to clarifications on the methodology about future debt set out in the Application, which Eastward agreed with in its Rebuttal Evidence. It is based on the best available evidence and is reasonable in the circumstances. The Board, therefore, approves the cost of debt as outlined in the Application, including the value-weighted calculation outlined EEI-IR-1(b).

4.9 Deferral Accounts, including RDA and CRP and their recovery

[186] Eastward has two major deferral accounts which had to be addressed in this proceeding. They are the Revenue Deficiency Account (RDA) and the Customer Retention Program (CRP) Account. The RDA was designed to allow a new utility to invest in infrastructure as it grew its customer base, to incentivize new customers by charging rates that were below the full cost of service. It is a somewhat unusual feature of the RDA account that it is still in place some 23 years after Eastward was granted its franchise. It reflects the challenges associated with developing natural gas infrastructure and a sustainable client base in Nova Scotia. The CRP was created in 2016 to address

significant competitive pressures from alternative energy sources, again by reducing rates below full cost recovery. The CRP ended in 2023. In 2024, Eastward applied to the Board requesting an energy rider mechanism to start paying down the CRP.

[187] The Board approved an energy rider with a cap of \$1.00/GJ. That said, the Board ordered that recoveries be applied to the RDA first. The RDA is a standard deferral account, in that it is treated as a regulatory asset, included in rate base, and earns Eastward's allowed rate of return. The CRP was approved on the basis that it would be carried at a fixed 4% interest rate. Accordingly, to protect ratepayers, since the RDA had a higher carrying cost, the Board ordered that the amounts collected from the energy rider would be applied to pay down the RDA first. The outstanding balances in these accounts were approximately \$49.9 million for the CRP and \$16.3 million for the RDA when the application was filed. In the application, Eastward proposed to increase the energy rider cap to \$1.50/GJ for all rate classes. Assuming the capped amount was collected throughout the test years, this was projected to eliminate the RDA balance by the end of 2028, and the CRP balance would be reduced to \$36.9 million by the end of the test period.

[188] The settlement agreement provides that the energy rider cap be left at \$1.00/GJ for the RSC and GSC customers. However, the proposed cap in the settlement agreement is \$0.65/GJ for RC3. This means that the RDA is now projected to be retired later in the test period. There will be a projected balance in the CRP deferral account at the end of the test period which is forecast to carry forward to approximately 2034 based on current volume forecasts. The Board questioned the fairness of having a lower cap for the RC3 customers. Counsel for Michelin and Dalhousie submitted that the lower cap

amount "...reflects a midway compromise between an energy-based recovery and an asset-based recovery, which implicitly recognizes that the RC3 customers already pay more than the cost to serve them." [Exhibit E-39, p. 2] This position was carried over into Michelin and Dalhousie's Closing Submissions. Eastward appears to adopt this position in its Closing Submission.

[189] The Board questioned Eastward about why the RC3 customers would not have to pay for a longer period if they were charged less per GJ under the energy rider. The genesis of this questioning assumed a 100% energy-based allocator as between rate classes. The Board raised Exhibit E-1, PDF page 408, Table 5, with the Eastward panel. The premise of the Board questions was that, based on the balances shown in Table 5, why would the repayment period not be longer for the RC3 class if it paid a lower amount per GJ. In response, SME noted that the settlement agreement resulted in a "modified" energy allocator for the RDA and CRP deferral accounts. In follow up questions from Ms. Rubin, the Eastward panel asserted that the balances set out in Table 5 were total deferral account collections and not deferral balances segregated by customer class. Table 5 is reproduced below:

TABLE 5 - 2027 ALLOCATED REVENUE REQUIREMENT BY FUNCTION AND DRIVER (\$'000)

Function	Function Total	GSC- Demand	GSC- Energy	GSC- Site	GSC- Deferrals	RC3- Demand	RC3- Energy	RC3- Site	RC3- Deferrals	RSC- Demand	RSC- Energy	RSC- Site	RSC- Deferrals
Elevated Pressure	10,400	7,110	0	0	0	2,762	0	0	0	527	0	0	0
Regulating Stations	1,817	1,242	0	0	0	483	0	0	0	92	0	0	0
Mains	25,938	18,343	0	0	0	1,403	0	0	0	6,192	0	0	0
Services	9,598	0	0	4,530	0	0	0	90	0	0	0	4,978	0
Metering	2,773	0	0	2,180	0	0	0	167	0	0	0	426	0
Marketing & Sales	2,491	0	830	492	0	0	358	2	0	0	57	751	0
Penalties and Service	(183)	0	0	(72)	0	0	0	(0)	0	0	0	(110)	0
Deferrals	13,251	0	0	0	8,830	0	0	0	3,814	0	0	0	607
Total	66,084	26,695	830	7,130	8,830	4,648	358	259	3,814	6,811	57	6,044	607
Rate Class Total			43,485				9,079				13,519		

[Exhibit E-1, Table 5, p. 408]

[190] Michelin and Dalhousie's position was set out at page 4 of its Closing

Submissions:

For purposes of the settlement, Michelin/Dalhousie accept the rider for all classes remaining energy-based, but as a compromise, the effective weighting for RC3 is adjusted such that each GJ consumed by RC3 counts at 0.65 rather than 1.0. This is an adjusted energy allocator, not a change in the type of allocator. The balances, on a global basis, are still projected to be paid down in their entirety in the short term: the RDA by 2029, and the CRP by approximately 2034 based on current volume forecasts. As confirmed by the Eastward panel during the clarifying questions by counsel for Michelin/Dalhousie, with reference to Table 5 of E-1, pdf page 408, there is no "under-recovery" intra-class as a result of the settlement. With the settlement, the overall amount to be collected each year has changed as the cap is no longer \$1.50/GJ and the amounts collected by class each year has changed. And the allocator remains the same for all rate classes, but the value per GJ consumed by an RC3 customer is \$0.65, rather than \$1. The ultimate balance that is collected from each class will change, but for all classes, the balance will be paid off as of the same date.

[191] In its Closing Submissions, Eastward submitted that the Board's concerns were based on a misunderstanding of Table 5:

The fairness concern raised in respect of the \$0.65/GJ RC3 rider is premised on treating the RDA and CRP as though they are separate, class-specific balances. They are not. The Settlement Agreement preserves the deferral accounts as common balances and modifies only the weighted energy-based collection mechanism by which those common balances are recovered.

The settlement does not treat the RDA or CRP as though each customer class has its own separate, fixed deferral balance that must be paid down independently. Instead, the deferral accounts remain common balances. The settlement changes only the rate and weighting of future collections from each class. Recovery continues to be based on energy consumption, but the energy allocator is modified so that each gigajoule consumed by RSC and GSC customers is weighted at \$1.00, while each gigajoule consumed by RC3 customers is weighted at \$0.65.

On that approach, the issue is not whether RC3's separate balance is paid down more slowly. There is no separate RC3 balance being amortized on its own track. Rather, all collections are applied to the same overall deferral balance, and all classes continue contributing under the weighted energy rider until that common balance is extinguished. In that sense, the settlement changes the distribution of contributions among classes, but not the structure of the account: the balance remains a single shared obligation that is paid off at one point in time.

[Eastward Closing Submissions, p.19]

4.9.1 Findings

[192] In 2024 NSUARB 217, in response to concerns raised by intervenors, the Board directed Eastward to engage with stakeholders and address the proper allocation of the energy rider among rate classes in a subsequent GRA:

[57] The Board notes there has been no cost-of-service study for the issues related to either the CRP or the RDA. Eastward was directed to consider the allocation of the CRP deferral in its next general rate application, along with a proposal to amortize the CRP. Eastward proceeded with the present application based on an “energy allocator” methodology”, without completing an appropriate review of the cost allocation. While Eastward argued that parties had not had a chance to consider the cost allocation related to the RDA recovery, the same could be said about the CRP recovery. [58] The Board finds that the Recovery Rate can be collected from customers starting as early as January 1, 2025, and applied to the RDA. Eastward is directed to track revenue under the Recovery Rate by rate class. The cost allocation will be confirmed and applied to the respective customer classes later, after a cost-of-service study is completed. If some classes have contributed under the Recovery Rate when they were not required to under cost-of-service principles, or they contributed too much, a mechanism will be implemented to either refund the amounts to those customers, with interest, or to apply the balance as otherwise directed by the Board in the next general rate application. [59] Accordingly, the Board approves the Recovery Rate as amended in this decision, starting as early as January 1, 2025, subject to Eastward providing tariff language for the approved Recovery Rate rider in a compliance filing to be filed by January 10, 2025. The cost allocation will be confirmed and applied to the respective customer classes after a cost-of-service study is completed. In addition to the directions given to Eastward about the CRP, the Board also directs Eastward to develop an appropriate cost allocation methodology for the RDA in its next general rate application or by the end of 2026.

[193] Eastward’s application and cost-of-service study in the 2026 GRA allocated the deferral rider recoveries based on a 100% energy allocation for both the RDA and the CRP. Mr. Bowman recommended that the CRP should be recovered on a straight-line basis over the next 36 years, allocating this amortization “...in direct proportion to depreciation expense for all other assets.” Mr. Bowman was of the view that there was no clear evidence that an equalized \$/GJ was the best rider design for collecting the RDA but acknowledged “...it is likely the simplest and most practical collection approach...”

[194] The Board assumed that its direction was being followed in the application, and that an energy allocator methodology was being proposed to recover both the RDA and CRP deferrals and allocate them between rate classes. Table 5, which appears to be

the revenue tracking discussed in the 2024 decision, was used in questioning, and show recoveries by rate class. If all rate classes are paying the same amount per GJ, and recoveries are also allocated based on energy consumption, it is a relatively simple mathematical exercise to determine the balances left to be recovered by each rate class, and, in fact, if there has been any over or under recovery, as discussed in the Board's 2024 decision. However, it is apparent that no individual deferral balances have been established, and none are proposed by any of the parties to the settlement agreement. It appears the parties have agreed to forego any reconciliation contemplated in the Board's 2024 decision. While essentially bypassing the Board's directives is not without some regulatory conceptual difficulties, the Board recognizes that the difference between what was proposed by Mr. Bowman and what Eastward had proposed in the application was significant. A 36-year amortization of the CRP, allocated in proportion to asset depreciation expense, if accepted by the Board, would have significantly shifted the burden of the CRP deferral to customer classes other than the RC3 class.

[195] While the Board has some residual concerns about the fairness of the proposed different treatment of the classes under the energy rider, a settlement agreement is a series of puts and takes. Each signatory weighs the risk of success if the matter is adjudicated against the certainty of a particular result and whether that result is acceptable in all the circumstances. In this case, at least in respect of the CRP deferral, there is a legitimate issue as to whether an energy allocator or an asset allocator is the appropriate methodology. The adjudicated outcome on that issue had material potential downside repercussions for each rate class. These downside risks have been addressed in the settlement agreement by the compromise discussed in the submissions. In these

circumstances, as all parties end up with a lower rider amount, and the RDA deferral account is expected to be fully repaid during the test period, the Board is prepared to approve this compromise between competing regulatory principles, as set out in the settlement agreement.

[196] In adopting the settlement agreement, the Board makes no finding about which allocation methodology for the CRP rider is best supported by public utility principles. Given that it is anticipated there will still be a CPR balance, after the test years for this GRA, the issue may come up again. However, at this stage, given that the settlement agreement addresses the allocation issue for the next three years, and seeks no reconciliation for past amounts, it would appear to the Board that any further allocation issues, if any, would be limited to amounts outstanding in the CPR deferral account at the end of the 2029 test year.

[197] Finally, the Board will address another issue arising from the deferral accounts. Despite the projection that the RDA deferral account will be eliminated during the test period, Eastward proposes not to eliminate the account even if it attains a zero balance. However, Eastward wants to reduce the cap from \$50 million to \$25 million. The basis appears to be to provide some financial flexibility given the volatile nature of the energy space. The Eastward panel also discussed the ability to address certain projections in the rate study if they turn out to be erroneous. The settlement agreement does not alter this proposal.

[198] The Board will allow Eastward to maintain the RDA, with a cap of \$25 million through the test period but Eastward should in no way take this as an assurance that such an approval will continue beyond the test years. In fact, with Eastward projecting to

achieve its full cost of service in the test years, there should be no need to continue with an RDA once the outstanding balance has been recovered from ratepayers. With respect to projections, established ratemaking principles require utilities to make their projections as accurately as they can. Deferral accounts like the RDA are not intended to provide a buffer for projections that turn out to be wrong.

[199] The Board will comment on one other deferral account. Eastward proposes to create a deferral account and amortize approximately \$1.4 million dollars of forecasted preparation and hearing related costs for this GRA. The proposal is to amortize these costs in equal amounts over the test period. The settlement agreement does not alter this proposal. Ordinarily, costs of this nature are considered operating costs. The Board has refused NS Power similar capitalized treatment for regulatory hearing costs on the basis they are operating costs. Given the settlement agreement, the Board will allow the capitalization of these costs. In future, however, the Board would expect these costs to be included as operating expenses. While they could potentially be recovered over more than one year for rate smoothing purposes, they should not be classified as a regulatory asset attracting a rate of return.

4.10 Distribution Service Rules, Regulations and Charges

[200] The Application proposes several changes to Eastward's Distribution Service Rules (Rules), as outlined in Table 17.0, pages 151–154 of the application. Most amendments address housekeeping items, such as updating references to the new Nova Scotia Energy Board, or are designed to simplify the process for potential customers and clarify the Rules. The document also incorporates the Special Charges Schedule, including fee increases based on Eastward's review of internal meter set work order costs. Because residential and commercial costs are consistent, they have been combined into

a single fee for all meter types. Additionally, Service Lines fees were updated to reflect rising supplier and municipal construction costs. No party had objections to the proposed updated Rules.

4.10.1 Findings

[201] The Board finds that the revisions provided in Table 17.0 of Eastward's Application provide greater clarity and are appropriate. The Board approves the revised Rules.

4.11 Incentive Programs

[202] Eastward proposes to maintain the same incentive and rebate programs that were approved in the 2024-2026 GRA. They will continue to apply to new and existing Multi-Unit Residential buildings (MURB) and for new construction and existing single-family homes. These incentives relate to the installation of natural gas space heating and domestic hot water systems. There is also an equipment replacement rebate for existing Eastward customers to assist in maintaining them on the natural gas system. Eastward operates in a competitive market with respect to energy sources. Electricity, heating oil, firewood and propane all compete with Eastward to varying degrees. In the Application, Eastward highlighted significant incentive programs offered by EfficiencyOne to MURB customers to assist with electrification. Eastward says its revenue from MURB, is important to maintain affordable rates for current and future customers.

[203] Eastward proposes to shift its focus since the implementation of the MURB incentive program in 2024. Eastward discovered that incentives targeted at space heating systems had little impact on customer behaviour. On the other hand, incentives targeting domestic hot water heating showed more promise. Therefore, Eastward has chosen to

reallocate its MURB incentive budget and offer an incentive of \$350/residential unit for MURBs who install a natural gas-based domestic hot water system.

[204] The single-family residential program targets both heating and hot water. For existing construction, Eastward offers rebates ranging from \$1,000 to \$2,500 to eligible homes currently heated with furnace oil, propane, wood or electricity to assist with conversion to natural gas. The rebates apply to natural gas boilers or furnaces, natural gas water heaters, combination natural gas boilers/furnaces and water heaters, natural gas fireplaces with a blower, natural gas absorption heat pumps and propane to natural gas conversion kits. For new construction single-family residential homes, where no conversion is involved, subject to eligibility criteria, the rebate applies to natural gas boilers or furnaces, natural gas water heaters, natural gas fireplaces with a blower and natural gas absorption heat pumps. Eastward also offers a rebate for single-family homes that are existing Eastward customers to assist with replacing end-of-life equipment such as natural gas combination boilers or combination natural gas furnaces and water heaters, natural gas boilers or furnaces and natural gas water heaters. The annual cost of these incentives for the test years is forecast at \$1.3 million. These are proposed to be amortized. In response to a directive from the Board in the 2024-2026 GRA about studying the appropriate amortization period, Eastward proposes a 25-year amortization, which is reflective of the estimated life of the heating equipment.

[205] In his Opening Statement, Mr. Borden alluded to the fact that, in his evidence, he had recommended that the Board deny Eastward's incentive programs "... because the incentives may not be necessary, are likely inconsistent with achieving Canada's long-term emissions objectives, and directly compete with ratepayer-funded

electric appliance incentives.” The settlement agreement leaves the incentive programs, as proposed by Eastward, intact. In these circumstances, Mr. Borden suggested that the Board should provide guidance about the role of natural gas subsidies in complying with federal emissions standards, as well as clarifying “...the role of gas appliance incentives in relation to ratepayer-funded electric appliance incentives, which directly compete against one another.”

[206] Cathcart took a different view about incentives, saying this type of program, or similar programs, “... is a key factor in Eastward's acquisition of new customers and in moving toward full cost recovery, and that without a program of this type, Eastward would not achieve these outcomes” [Exhibit E-20, p.108]. Eastward echoes this view explaining that incentives were a mechanism to level the playing field in a highly competitive industry. From Eastward's perspective, there is a long-run benefit of attracting or retaining customers through incentives. Eastward also pointed out that the commodity price is not the only factor potential customers consider when choosing options in this competitive market. Upfront costs can tip the balance when customers make choices. Eastward said incentives are a reasonable and prudent investment for the growth of a customer base that will ultimately result, in the long run, in lower rates.

4.11.1 Findings

[207] The first issue, at this stage, is whether the arguments for and against approval of the incentive programs should be weighed in this proceeding and a determination made about whether this aspect of the settlement agreement should be allowed or denied. The Board notes that some of Eastward's competitors have no regulated limits on their incentives. With respect to electricity, EfficiencyOne incentives are part of a demand side management response. Neither NS Power nor EfficiencyOne

appeared before the Board to argue against competing incentives. The Province supports the continued operation and development of a natural gas distribution system at affordable rates. While Mr. Borden raised legitimate points, in the Board's view, given there are arguments on both sides of the debate, it is a reasonable compromise to have potential challenges to the incentive programs, if any, deferred to a future application. It is a situation where, in considering the totality of the evidence, the arguments against allowing incentives are not so strong to convince the Board it would not be in the public interest to approve this settlement. The Board therefore accepts and approves the incentive program as agreed to in the settlement agreement.

[208] Further, the Board approves Eastward's request to maintain the Residential Retrofit Assistance Fund at \$500,000.

[209] Insofar as future guidance is concerned, the Board will say that there must be sufficient evidence that the proposed incentives influence customer behaviour to the extent necessary to justify the amount of the incentives. As well, any future application should elaborate on whether incentives have a materially negatively impact on government policy, particularly in relation to competing ratepayer-funded electric appliance incentives. Eastward should also discuss how incentives could address the factors in s. 6(2) of the *Energy and Regulatory Boards Act* and s. 22 (3A) of the *Gas Distribution Act*.

4.12 Application for Renewal of Franchise

[210] Eastward's current franchise rights to distribute natural gas to all or part of six counties in Nova Scotia expire in 2028. Eastward intends to file an application with the Board in 2027 to request a renewal of the franchise rights for an additional 25 years. The Board encourages Eastward to file its application as soon as practicable to ensure there

are no timing issues associated with the end of the current franchise. When the issue of the application for a renewal was discussed, it was pointed out during Board questioning that the Application included an estimate of \$3.3 million to process such an application. Ms. MacDonald advised that this estimate had been prepared based on estimated costs for an original application. She provided a revised estimate of \$600,000 for the anticipated franchise renewal application. Eastward agreed to incorporate this new amount in a compliance filing, although Ms. MacDonald indicated this will result in only a minor change, since the cost had been amortized over 25 years in the rate study.

4.13 Findings

[211] The Board agrees that the estimate for Eastward's franchise renewal application should be revised downwards to \$600,000 and that this figure is to be incorporated in the compliance filing.

4.14 Energy Transition

[212] In the Board's *2024-2026 GRA* Decision, the Board made extensive comments on the challenge Eastward faces. To be viable in the long-term, Eastward needs to grow its customer base and the demand for natural gas in the face of major decarbonization initiatives, both at the provincial and federal levels. In this application, Eastward discussed the potentially increasing role of natural gas in maintaining reliability and underpinning incremental renewable resources. There is continued discussion with the Province, industry and customers about the role of Eastward in achieving net-zero targets. There have been discussions about the opportunity for integrated energy systems and hybrid heating. Eastward continues to explore the potential use of its infrastructure in the hydrogen energy field. In the NSDOE's Opening Statement, the Province expressed continued support "...for safe, reliable, and affordable delivery of

natural gas to Nova Scotians, and in ensuring that rates approved by the Board are fair, evidence-based, and in the public interest.” The precise role of Eastward in the energy transition in Nova Scotia remains elusive. The hybrid heating and hydrogen prospects remain in early stages of consideration. Eastward is projecting a role in delivering natural gas to the two natural gas plants the IESO Nova Scotia is contemplating. It is not clear on the current record whether this assumption is correct.

[213] It appears to the Board that Eastward’s role in the energy transition is not materially clearer now than it was at the time of the *2024-2026 GRA* Decision. The Board understand this is a challenging environment. It can only encourage Eastward to diligently pursue all available options in aligning its business with the federal and provincial decarbonization goals.

5.0 COMPLIANCE FILING

[214] The Board issued various directives to Eastward in this decision, including:

1. The Board directs Eastward to update the lead/lag study in its next general rate application.
2. The Board directs Eastward to investigate and put forward a proposal on distribution mains cost recovery as raised by Mr. Bowman in Eastward’s next general rate application.
3. The Board directs the Company to provide an analysis of forecast versus actual new customer additions the 2027 to 2029 test period and explain the discrepancy between the actual and forecast values.
4. The Board directs Eastward to adopt the ALG depreciation methodology beginning in 2027.
5. The Board directs Eastward to file Ms. Nori’s detailed ALG and ELG calculations as part of the compliance filing.

6. The Board directs Eastward to file a new depreciation study with its next GRA, which is to include an assessment of net salvage values for the related test period. The assessment is to include, but not be limited to, the items set out in Paragraphs [100] and [101] of this decision.
7. The Board also directs that the depreciation study be IFRS compliant if Eastward determines it will be transitioning to IFRS reporting.
8. The Board directs that Eastward's next depreciation study provides a comprehensive assessment of asset service lives and Iowa curves, including the changes suggested by Mr. Madsen.
9. The Board directs that Eastward's next depreciation study include the following:
 - Detailed management notes for each account;
 - All analysis and studies performed by management for each asset to confirm the expected life; and
 - The peer analysis relied upon by the Company in an Excel file.
10. The Board directs that the amount of approximately \$3.3 million in Account 496.00 be adjusted down to \$600,000.
11. The Board directs Eastward to file annual reports about the capital spend and forecasted remaining spend for the Permits to Construct currently under construction and then provide a five-year true-up to feasibility results, where applicable. The annual reports are to provide a clear roadmap with measurable milestones for full cost recovery within its annual financial compliance report, following the framework currently used for Mains Feasibility Test projects.
12. The Board directs Eastward to incorporate the updated information about the Bedford Loop as set out in Undertaking U-8 into its compliance filing.
13. The Board directs Eastward to follow its suggested approach to International Financial Reporting Standards transition reporting; consisting of a report in early 2027 and continued reporting through its annual financial compliance report.
14. The Board directs Eastward to report in the next GRA on the IFRS transition analysis, related IT system requirements, including time carding and capital modules, the review of Eastward's capitalization policy against IAS 16, and an IFRS depreciation study if an IFRS transition is confirmed.

[215] Eastward is to file a compliance filing based on the Board's findings in this decision. The compliance filing is to include, among other things:

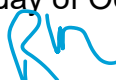
- Its revised Schedule of Rates, Tolls and Charges, subject to the Board's findings in this decision.
- All the tables from the Application updated to conform with the settlement agreement and this Decision.
- All the tables in the depreciation study updated to conform with the settlement agreement and this Decision, in Excel format.
- The tables from the attachment to the settlement agreement to reflect this compliance filing.

[216] Eastward is directed to file a compliance filing no later than two weeks after the date of this decision. Intervenor will have two weeks from the date that Eastward files its compliance filing to provide submissions to the Board. Eastward may file a reply within one week from the date the Intervenor file submissions.

[217] The Board approves the rate increases proposed in the settlement agreement for the customer classes in 2027, 2028 and 2029, subject to the Board's findings in this decision and to the Company's compliance filing. The rate increases per customer class, in each of the test years 2027-2029, is to be confirmed in the compliance filing.

[218] An Order will issue following the compliance filing.

DATED at Halifax, Nova Scotia, this 13th day of October, 2026.



Richard J. Melanson



Steven M. Murphy



Darlene Willcott