

NOVA SCOTIA ENERGY BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF A GENERAL RATE APPLICATION by **NOVA SCOTIA POWER INCORPORATED** for approval of certain revisions to its Rates, Charges and Regulations

BEFORE: Stephen T. McGrath, K.C., Chair
Roland A. Deveau, K.C., Vice Chair
Steven M. Murphy, MBA, P.Eng., Member

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Jennifer Power, Counsel
Geoff Breen, Counsel
Colin Clarke, Counsel

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

SMALL BUSINESS ADVOCATE
Melissa P. MacAdam, Counsel
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HEARING DATE(S): January 7-13, 2026

FINAL SUBMISSIONS: February 6, 2026

DECISION DATE: **March 25, 2026**

DECISION: **The application is approved as amended by the Board.
The revised rates will be confirmed in a compliance filing.**

TABLE OF CONTENTS

GLOSSARY OF ABBREVIATIONS.....	6
1.0 SUMMARY	8
2.0 BOARD'S AUTHORITY UNDER THE <i>PUBLIC UTILITIES ACT</i>	20
3.0 ANALYSIS AND FINDINGS	27
3.1 Should the Settlement Agreement be Approved?.....	27
3.1.1 Findings	33
3.2 Fuel and Purchased Power.....	35
3.2.1 Base Cost of Fuel.....	36
3.2.1.1 Findings	41
3.2.2 FAM Plan of Administration and Fuel Manual	42
3.2.2.1 Plan of Administration.....	42
3.2.2.2 Fuel Manual and Hedging Plan	43
3.2.2.3 Findings	44
3.3 Operating, Maintenance and General Costs.....	44
3.3.1 Overall Costs.....	44
3.3.1.1 Findings	54
3.3.2 Executive Compensation	61
3.3.2.1 Findings	63
3.4 Depreciation.....	64
3.4.1 Settlement Agreement Reduction in Depreciation and Accretion Expense	72
3.4.1.1 Net Salvage Costs	73
3.4.1.1.1 Production Plant.....	73
3.4.1.1.2 Transmission, Distribution and General Plant...	75
3.4.1.2 Estimated Average Asset Service Lives	77
3.4.1.3 Findings	78
3.4.1.3.1 Exclusion of Wreck Cove, Mersey and Tusket Hydro System Decommissioning Costs from Proposed Depreciation Rates	78
3.4.1.3.2 Adjustments to Net Salvage Rates	82
3.4.1.3.3 Adjustments to Estimated Asset Average Service Lives	94
3.4.2 Calculation of Depreciation Expense (ELG vs. ALG)	94
3.4.2.1 Findings	99
3.4.3 Asset Average Service Lives	115
3.4.3.1 Findings	118
3.4.4 Amortization Accounting for General Plant Assets.....	125
3.4.4.1 Findings	127
3.4.5 Submissions of the Nova Scotia Department of Energy.....	127
3.4.6 Depreciation – Summary.....	129
3.5 Regulatory Deferrals	134
3.5.1 Securitization Deferral	134
3.5.1.1 Background	134
3.5.1.2 Present Application.....	138
3.5.1.2.1 Findings	149

3.5.1.3	EIFEL Deferral.....	155
3.5.1.3.1	Findings	156
3.5.1.4	PHP Deferral	156
3.5.1.4.1	Findings	161
3.5.1.5	GRA Deferral.....	163
3.5.1.5.1	Findings	164
3.5.1.6	Payment of Interest on Deferral Accounts	166
3.6	Rate Base.....	167
3.6.1	Capital Additions	167
3.6.1.1	Findings.....	168
3.6.2	Maritime Link Capital Projects.....	170
3.6.2.1	Findings.....	171
3.6.3	Valuation and “Writing Down” of the Rate Base.....	172
3.6.3.1	Findings.....	178
3.6.3.1.1	The Value of the Rate Base.....	179
3.6.3.1.2	Assets No Longer “Used and Useful” and the Decarbonization Deferral Account.....	188
3.6.3.1.3	The Requirement for Prudence.....	192
3.6.4	Findings	197
3.7	Return on Equity and Capital Structure.....	197
3.7.1	The Fair Return Requirement	198
3.7.2	Overview of Cost of Capital Evidence	202
3.7.2.1	Return on Equity.....	202
3.7.2.2	Capital Structure (Equity Ratios)	206
3.7.3	Return on Equity Modeling	207
3.7.3.1	CAPM Models.....	207
3.7.3.2	DCF Models.....	212
3.7.3.3	Risk Premium Model.....	216
3.7.4	Party Submissions	217
3.7.5	Findings	220
3.7.5.1	Return on Equity.....	222
3.7.5.2	Capital Structure.....	236
3.8	Cost of Service Study	237
3.8.1	Findings	247
3.8.2	Minimum System v. Basic Customer Methods.....	248
3.8.2.1	Findings.....	257
3.8.3	Primary Distribution System.....	259
3.8.3.1	Findings.....	260
3.8.4	Peak Load Carrying Capability Adjustment.....	261
3.8.4.1	Findings.....	264
3.8.5	Other Cost-of-Service Issues Raised by Synapse	265
3.8.5.1	Findings.....	267
3.8.6	Issues Raised by Renewall Energy Inc.....	268
3.8.6.1	Findings.....	270
3.9	Rate Design	272
3.9.1	Innovation	272

3.9.1.1	Findings	273
3.9.2	Residential and Small General Customer Charges	274
3.9.2.1	Findings	276
3.10	Miscellaneous Charges and Regulations	277
3.10.1	OATT	277
3.10.1.1	Findings	281
3.10.2	AMI Opt-Out Fee	282
3.10.2.1	Findings	285
3.10.3	Revised Fees and Regulations	287
4.0	OTHER ISSUES	287
4.1	Demand Side Management Cost Recovery Rider	287
4.1.1	Findings	290
4.2	Storm Cost Recovery Rider	291
4.2.1	Findings	292
4.3	Climate Change Adaptation Plan	293
4.3.1	Findings	295
4.4	Lingan Unit 2 and Trenton Unit 5	296
4.4.1	Findings	298
4.5	Rate Setting – Alternative Form of Regulation	299
4.5.1	Findings	300
4.6	Implementation of New Rates (Cyber Incident Impact)	301
4.6.1	Findings	302
5.0	SUMMARY OF MAJOR FINDINGS AND DIRECTIVES	303
6.0	COMPLIANCE FILING	307

GLOSSARY OF ABBREVIATIONS

AA	Actual Adjustment
ACE	Annual Capital Expenditure
ADC	Active Demand Control
AEC	Affordable Energy Coalition
ALG	Average Group Life
AMI	Advanced Metering Infrastructure
ATL	Above-the-Line
AUC	Alberta Utilities Commission
BA	Balance Adjustment
BA ₁	Annual Volume Variance Adjustment
BA ₂	End of Approved DSM Term Adjustment
BTL	Below-the-Line
CAPM	Capital Asset Pricing Model
CBAS	Capacity-based Ancillary Services
COSS	Cost-of-Service Study
CT	Combustion Turbine
DCRR	Demand Side Management Cost Recovery Rider
DCF	Discounted Cash Flow
DDA	Decarbonization Deferral Account
DDM	Dividend Discount Model
DSM	Demand Side Management
E1	EfficiencyOne
EAA	Energy Access Agreement
EIFEL	Excessive Interest and Financing Expenses Limitation
ELG	Equal Group Life
ELIADC	Extra Large Industrial Active Demand Control
ELID	Extra Large Industrial Dispatchable
FAM	Fuel Adjustment Mechanism
FERC	United States Federal Energy Regulatory Commission
FFO:Debt	Funds from Operations to Debt
FLG	Federal Loan Guarantee
FTE	Full-time Equivalent Employees
GDP	Gross Domestic Product
GRA	General Rate Application
HAS	Hydro Asset Study
IESO Nova Scotia	Independent Energy System Operator Nova Scotia
IPP	Independent Power Producer
IRP	Integrated Resource Plan
IRs	Information Requests
IT	Information Technology
KMKNO	Kwilmu'kw Maw-klusuaqn Negotiation Office
LIIR	Large Industrial Interruptible Rider

MEUs	Municipal Electric Utilities of Nova Scotia
NARUC	National Association of Regulatory Utility Commissioners
NBV	Net Book Value
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NPV	Net Present Value
NRR	Department of Natural Resources and Renewables
NSPML	Nova Scotia Power Maritime Link
NSUARB	Nova Scotia Utility and Review Board
OATT	Open Access Transmission Tariff
OM&G	Operating, Maintenance and General
OT	Operational Technology
PDF	Portable Document Format
PHP	Port Hawkesbury Paper
POA	Plan of Administration
PUA	Public Utilities Act
REI	Renewall Energy Inc.
RES	Renewable Electricity Standards
SCRR	Storm Cost Recovery Rider
S&P	Standard & Poors
TVP	Time-varying Pricing
UAD	Utility Asset Disposition
WACC	Weighted Average Cost of Capital

1.0 SUMMARY

[1] The Nova Scotia Energy Board is keenly aware that electricity rates are already challenging for many customers, and any rate increase will be difficult, especially for those with low or fixed incomes. However, the Board does not have the authority to provide special rates for these customers and, as noted by the Nova Scotia Court of Appeal, the Board's regulatory power under the *Public Utilities Act* is not an instrument of social policy.

[2] The *Public Utilities Act* entitles a utility the opportunity to recover its prudently incurred costs in providing a service to the public and an opportunity to earn a reasonable profit. While the Board can disallow costs found to be imprudent or unreasonable, absent such a finding, a utility's costs must be reflected in the rates paid by customers. The Board does not have the legal authority to disallow the recovery of legitimate costs to make rates more affordable.

[3] On September 18, 2025, NS Power filed a general rate application (GRA) with the Energy Board to change its rates for 2026 and 2027. The company proposed average rate increases across all customer classes effective on each of January 1, 2026, and January 1, 2027 (1.8% in 2026 and 2.4% in 2027). However, proposed rate increases vary across different customer classes, with residential customer rates proposed to increase 3.8% and 4.1% in 2026 and 2027, respectively. Some of the general and industrial customer classes will have more modest increases or even reductions in the proposed rates.

[4] NS Power previously advised the Board that the application was the "result of an extensive collaborative process involving NS Power and customer representatives

and it is being filed with the support of those representatives for the outcomes of the GRA". NS Power filed the settlement agreement on November 5, 2025.

[5] NS Power proposes changes to both its fuel and non-fuel costs. The rate increases are to cover the costs of providing service to its customers, including the generation, transmission and distribution of electricity as well as providing other services to its customers such as connection requests and customer service. NS Power outlined in its application that it is operating in complex circumstances. Indeed, NS Power is immersed in a multifaceted energy transition. The challenges include retiring its coal plants by 2030; providing 80% of its electricity from renewable resources on the same timeline; handling the worsening impact of climate conditions; and applying new technologies both on its grid and in providing innovative rates and service solutions to its customers.

[6] While the settlement agreement with the utility's customer representatives meant that these intervenors did not present evidence in the hearing to oppose the application, Board Counsel did engage various expert consultants to review the application. These included the proposed operating, maintenance and general (OM&G) costs, fuel costs, the cost of capital (including return on equity), depreciation, cost-of-service and other rate design issues. Additionally, intervenors, Board staff and Board Counsel consultants asked hundreds of information requests and received thousands of pages of additional information from NS Power about the application. The Board held its public hearing from January 7 to 9, 12 and 13, 2026. Written closing submissions were completed on February 6, 2026. The Board also received many letters of comment from customers.

[7] The general rate application contemplated securitization as an important new element, which NS Power described as the “centerpiece” of its application. The utility said it wishes to securitize about \$704 million of its coal plants and thermal-related assets. Securitization is a complex commercial transaction that has the effect of reducing financing costs, thereby mitigating rate increases for customers. If securitization had occurred by January 1, 2026, as originally intended by NS Power, the utility estimated that costs would be reduced for customers by about \$90 million over 2026 and 2027. Given that the securitization did not occur by year-end 2025, NS Power requested a “securitization deferral”. It asked that this regulatory account be used to defer financing costs and depreciation expense from January 1, 2026, onwards, related to the \$704 million in coal-related assets it intends to retire. The amount collected in the deferral is proposed to be added to the total securitized amount.

[8] Morrison Park Advisors, a consultant firm engaged by Board Counsel to review the credit rating elements of the rate application, noted that NS Power had suffered a credit rating downgrade in November 2022 to BBB-, which is the lowest investment grade status and just one level above “junk bond” status. Morrison Park cautioned that the Board needs to be mindful of the risk of the utility dropping to “junk bond” status. It said a further downgrade would have “potentially significant consequences”, noting the importance of NS Power maintaining a minimum target of 10% funds from operations to debt (FFO:Debt), that being a key credit metric monitored by credit rating agencies. It concluded that if both the securitization proceeds and the proposed rate increases in this application are approved, the utility’s credit metrics should improve from their current precarious levels. Any delay in completing the securitization, or a partial approval of the

proposed rate increases, or both, would further limit the utility's ability to meet the credit metrics required by the rating agencies. However, Morrison Park stated that absent both the rate increases and the securitization, there was a likelihood that NS Power's credit rating could be downgraded even further. This would result in higher financing costs, which could amount to at least \$25 million more each year in borrowing costs that would have to be included in customer rates.

[9] Securitization requires legislative action by the Province to allow it to proceed, something the Province has indicated it is not prepared to do, at least at this time. While it enacted a provision allowing securitization in the *Public Utilities Act*, the section is not yet in force and regulations still need to be developed. The Province's primary concern is that the coal plant assets proposed to be securitized are overvalued because insufficient depreciation was taken on the assets in the past and NS Power continued to invest in these assets despite nearer term retirement obligations. Settlement agreements in past rate applications in 2011 and 2014, kept depreciation rates lower than NS Power proposed. As a result, the value of the coal plant assets on which NS Power was able to earn a return was higher than it otherwise would have been if higher depreciation expenses had been applied.

[10] However, as canvassed in this decision, the settlement agreements in prior general rate applications had the effect of mitigating the rate impacts for customers at the time by avoiding accelerated depreciation on coal assets to be retired. Further, utility investors provide the upfront capital required to purchase or construct utility infrastructure to serve customers, and customers who use that infrastructure repay those costs over time as they receive the benefits of service. To attract and retain this investment, investors

are given the opportunity to earn a fair return on the capital invested, as well as ultimately recoup the amounts invested. The rate base value (including the value of the coal plant assets) presented in this general rate application follows generally accepted regulatory practice and the default method explicitly referenced in the *Public Utilities Act*. As described by the Supreme Court of Canada, a fair return means “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”. A low return on rate base may discourage investment in the utility. It may also lead to a poor credit rating, which would cause debt markets to increase the rate of interest on funds used by the utility to provide service. This may result in the utility's rates increasing just to cover additional borrowing costs. It may even cause it to be excluded from participating in some debt markets altogether. Morrison Park reiterated these concerns in the present matter.

[11] NS Power and representatives of most of its customer classes presented a settlement agreement in this matter. The Nova Scotia Utility and Review Board (NSUARB) has considered settlement agreements in past matters, stating that the Board's ultimate duty under the *Public Utilities Act* is to ensure that the terms of such an agreement are just, reasonable and in the public interest. As part of this exercise, the Board must ensure that "only those costs which are fair, justifiable and prudently incurred" by the utility are ultimately approved. There is no doubt that a settlement agreement concluded between the utility and most of its customer classes should attract significant weight.

[12] However, the circumstances leading to the settlement agreement in the present matter are different than in prior applications in that the parties negotiated the settlement agreement before the application was filed, rather than after a full evidentiary record was presented to the Board, including an independent review by various Board Counsel consultants about different components of the application. This is a factor that affects the weight the Board assigns to the settlement agreement. While the agreement is still entitled to some deference, this does change the Board's perspective on the settlement. It does not have the full benefit of the parties' views of the application, and the value assigned to various compromises reached in achieving a negotiated settlement. In some instances, the Board was left uncertain about whether certain perspectives had been analyzed or considered.

[13] Following its review of the evidence, the submissions and the law, while the settlement agreement does contain many terms that are appropriate and should be adopted, the Board concludes that some amendments to the application are required to ensure just and reasonable rates. The Board finds that the amendments to the application outlined in the remainder of this decision are appropriate and are necessary in the public interest.

[14] The Board finds that securitization could prove beneficial for customers by potentially reducing financing costs on the securitized amount, compared to reflecting the assets on the company's balance sheet. Whether securitization ultimately proceeds is a policy matter for the Province to decide. In the interim, the Board approves the securitization deferral to address costs that NS Power removed from rates in this application because it expected securitization to proceed. In terms of the Province's

concerns about the value of coal plant assets to be securitized, the Board finds that the past settlements noted by the Province in 2011 and 2014 were made at the time to lower customer rates. Further, under the *Public Utilities Act*, and consistent with generally accepted utility ratemaking principles across North America, the utility is entitled to recover its prudently incurred costs along with a reasonable return on and of its invested capital. To find otherwise could have significant negative financial implications for NS Power in the form of increased costs, leading to higher rates for its customers.

[15] NS Power's proposed return on equity was also an issue raised at the hearing. There was extensive expert evidence on this issue from two sources. Concentric Energy Advisors, NS Power's expert, recommended an average return on equity of 9.4% from its models (Undertaking U-14), while the same models applied by Dr. Sean Cleary, the Board Counsel's consultant, yielded an average recommended return on equity of 7.6%. Each of their models, inputs and assumptions had strengths and weaknesses. The Board finds that neither of the experts' recommended averages meet the "fair return standard", described above, with Dr. Cleary's recommendation being too low and Concentric's being too high. The appropriate return on equity is somewhere in between the two. In its application, NS Power asked to maintain its current return on equity of 9.0% for ratemaking purposes, with an earnings band of 8.75% to 9.25%. This request was supported by the customer classes in the settlement agreement.

[16] Dr. Cleary acknowledged in a recent proceeding before the Board that if the return was set at 7.6%, it would be the lowest recommended return on equity for a utility in Canada. Setting a return on equity at 7.6% would materially reduce NS Power's funds from operations and make its 10% FFO:Debt target more difficult to achieve. NS Power's

current credit rating from Standard & Poors (S&P) already places it in the bottom 10% of utilities in North America. A reduction in the return on equity below that proposed in the application would aggravate the situation. In the circumstances, the Board finds it would not be in the public interest to approve a return on equity that does not meet the fair return standard and deviates materially from the range of equity returns authorized for similar utilities across Canada. It finds that the current return on equity and capital structure should be maintained.

[17] Accordingly, the Board finds that most components of the settlement agreement appropriately resolve issues raised in the application. As a result, subject to its findings below that amend the application, the Board approves the following:

- Maintaining NS Power's current return on equity of 9.0%, with an earnings band of 8.75% to 9.25%. The equity thickness for rate setting purposes remains at 40.0%;
- The establishment of the securitization deferral to defer depreciation expenses and financing costs related to the coal plants and thermal-related assets within the scope of the Decarbonization Deferral Account, but only effective from the date the rate increases in this application are implemented;
- NS Power's proposed depreciation rates;
- The proposed cost-of-service methodology and cost allocation among the various customer classes, except that NS Power is directed to implement a load carrying capability adjustment to account for the demand component served by the minimum system used to classify distribution system costs and to address other cost-of-service issues as noted in this decision;
- The PHP Deferral account, based on the assumptions in the settlement agreement, to track any variances in revenue between that which would occur based on the assumptions in the cost-of-service study treating PHP as an Above-the-Line customer versus that which results from the eventual Board-approved tariff for PHP. NS Power estimated \$18.2 million would accrue in the deferral if PHP remains as a Below-the-Line customer for the entirety of 2026 (Undertaking U-2), and there would also be a \$5.7 million fuel balance captured under the FAM;

- The EIFEL deferral, allowing NS Power to defer incremental tax expense of about \$7 million if an exemption is not enacted by the Government of Canada as it has announced;
- The inclusion of four Maritime Link transmission capital projects in rate base. The amount to be included in rate base is the net book value of these assets as of the date of the Board's Order;
- Continuing the Storm Cost Recovery Rider pilot in 2026 and 2027, but on a symmetrical basis, which allows for underspent Level 3 and 4 costs to be returned to customers;
- The change to the tariff language for the Demand Side Management Cost Recovery Rider;
- Revising the Open Access Transmission Tariff (OATT) rates to reflect changes in the generation and transmission asset mix and costs, changes in system usage since the last update in the 2023-2024 GRA, Board directives from the 2023-2024 GRA, and the revised methodology from the 2024 Cost of Service proceeding; and
- Other miscellaneous fee changes under the Schedule of Charges, such as for connection, reconnection, returned cheques, installation of recording equipment, contribution for three-phase service, load research charges, and pole attachment fees.

[18] While the Board is satisfied that many of the elements of the settlement agreement can be accepted, it has made several adjustments in this decision to reduce NS Power's proposed revenue requirement or adjust the allocation of costs among customer classes, including:

- A further reduction of \$8 million in Operating, Maintenance and General expenses in each of 2026 and 2027 (over and above the \$9 million outlined in the settlement agreement);
- A reduction in NS Power's proposed executive compensation in both 2026 and 2027 to be consistent with the *Nova Scotia Power Incorporated Regulations*;
- The denial of NS Power's proposed deferral of general rate application OM&G costs (GRA deferral) for collection over the 2026-2027 period;
- A reduction of \$1.8 million in fuel and purchased power costs in 2026 to reflect the present estimate for Maritime Link assessment costs, and to update the current 2027 estimate;

- A peak load carrying capability adjustment of 0.4 kW per customer applied as a credit to the non-coincidental peak demand for determining the minimum system demand allocators for the distribution system costs (this change transfers the related costs from domestic, small general and unmetered customers to other rate classes) (Undertaking U-6); and
- The denial of the proposed AMI opt-out fee.

[19] Other issues were raised in this application which could also have impacted the proposed rate increases. These issues included considering a different depreciation treatment for the utility's assets and applying different cost-of-service procedures for the allocation of costs among the various customer classes.

[20] Under a cost-of-service model, the objective is to fairly allocate costs to customers based on cost causation. A change in the cost-of-service methodology for classifying distribution system costs (using the basic customer method) would have reallocated costs from domestic, small general and unmetered customer classes to other rate classes (Undertaking U-5). This change alone would have reduced the proposed rate increases for domestic customers from 3.8% and 4.1% in 2026 and 2027, respectively, to 2.2% and 2.8%. Larger reductions would have occurred for the small general class. However, this would have resulted in opposite rate impacts on other customer classes.

[21] It would be inappropriate to direct the use of the basic customer method simply to reduce the rate increase for residential, small general and unmetered customers. It would be just as inappropriate not to do so because of the impact that would have on other customers (with or without rate rider impacts). However, the parties did not fully press this issue in this proceeding due to the settlement agreement and the Board requires more information to further assess the cost causation basis for adopting the basic customer method. These issues will be brought before the Board for further consideration in a cost-of-service proceeding later this year.

[22] Similar considerations apply to the potential implementation of depreciation related issues. Assuming securitization were to proceed, the Board received evidence that a change from the Equal Life Group (ELG) to Average Life Group (ALG) depreciation methodology would have reduced NS Power's revenue requirement in each of 2026 and 2027, thereby reducing rates for all classes. Further, the Board considers such a change may be a more appropriate reflection of depreciation over the service lives of the company's assets. However, given the failure of securitization to occur by year-end 2025, the Board is not inclined to apply these changes because of the continued risk of a credit downgrade. A change in NS Power's depreciation expense from what is proposed in the application would negatively affect its FFO:Debt credit metrics and risk a credit downgrade. As Morrison Park noted, a further credit downgrade would have serious long-term cost consequences resulting in higher costs for ratepayers.

[23] The Board has also issued several directives to NS Power, summarized as follows, and set out in more detail at the end of this decision:

- To file an updated depreciation study with its next general rate application, with several directives to address a comparison of the ALG and ELG methodologies, and certain specified asset service life accounts;
- To report the results of its consultation process with interested parties about the decommissioning of hydro plants, no later than October 1, 2026, and every six months thereafter;
- To address the additional cost-of-service concerns raised by Synapse in its application to the Board later this year, in addition to the review of the minimum system v. basic customer method for allocating distribution system costs;

- To address the issues raised by Renewall in its closing submissions, if the utility brings forward any application relating to the OATT tariff or charges before responsibility for the transmission tariff is transferred to the Nova Scotia Independent Energy System Operator;
- To address the setting of customer charges in its next general rate application;
- To file a revised Climate Change Adaptation Plan by October 1, 2026, outlining climate related impacts on the utility's resources, activities and assets; actions to address the issues identified; potential and likely adaptation measures; and any challenges to mitigating risks; and
- Unless NS Power is able to provide a compelling reason in its compliance filing demonstrating that it is not possible to use AMI data to avoid prorating bills to accommodate its proposed rate increase, the Board directs that the bills covering the time that the new rates come into effect be prepared on the basis that the energy consumed in the billing period is charged at the actual rate that was in effect when the energy was actually used.

[24] The Board is satisfied that its findings in this decision result in just and reasonable rates for NS Power and that where it has departed from the terms of the settlement agreement it was in the public interest to do so. With the approval of the application, as amended, the Board concludes that NS Power will have a fair opportunity to recover its prudently incurred costs for the service it provides to its customers and to earn a fair return that allows it to attract new capital investment and maintain the financial integrity of the utility. Based on the evidence in this matter, this should also support the

company's credit metrics above target levels and avoid the negative consequences from a credit downgrade, which would impose further costs on NS Power and its customers.

2.0 BOARD'S AUTHORITY UNDER THE *PUBLIC UTILITIES ACT*

[25] The Board is an administrative body, established under the *Energy and Regulatory Boards Act*, SNS 2024, c 2, Schedule A. It must follow legislative requirements and administrative law principles. The Board's decisions may be appealed to the Nova Scotia Court of Appeal on any question of law or its jurisdiction. The Supreme Court of Nova Scotia may also judicially review aspects of its decisions.

[26] The Board is what has sometimes been referred to as a "creature of statute". In *Administrative Law in Canada*, 7th ed, p. 137 (LexisNexis Canada, 2022), Sara Blake described the powers of such entities:

An administrative tribunal is created by statute and has only those powers conferred on it by statute. It has no inherent power to undertake proceedings or to make an order that affects a person's substantive rights or obligations. Most Interpretation Acts confer on tribunals all powers that are necessary to enable them to make the decisions and do the things they are expressly empowered to do. The powers that exist by necessary implication may be deduced from the wording of the Act, its structure, and its purpose. A tribunal's powers should be interpreted so as to enable the tribunal to fulfil the purposes of the statute rather than sterilized by overly technical interpretation, but statutory powers may not be expanded to accomplish what the tribunal thinks it ought to do to further its mandate in the public interest. If a tribunal has broad authority to make any order to remedy a violation of the Act, the remedy must be related to the violation, its consequences and the purposes of the Act.

[27] The NSUARB summarized the application of these principles in *Re Nova Scotia Power Incorporated* [2018 NSUARB 45]:

[47] The UARB is a creature of statute and can only obtain jurisdiction from two sources: one, express grant of jurisdiction under the *PUA* and under other statutes (express powers); and two, from common law by application of the doctrine of jurisdiction by necessary implication (implicit powers).

[48] In *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, [2006] SCC 4, the majority decision stated, at paragraph 51, that:

...the powers conferred by an enabling statute are construed to include not only those expressly granted but also, by implication, all powers which are practically necessary for the accomplishment of the object intended to be secured by the statutory regime created by the legislature.

[49] The majority also held, at paragraph 74 of the *ATCO Gas* decision, that:

...the doctrine of jurisdiction by necessary implication will be of less help in the case of broadly drawn powers than for narrowly drawn ones. Broadly drawn powers will necessarily be limited to only what is rationally related to the purpose of the regulatory framework.

[28] The Board's general functions, power, duties and jurisdiction are expressly addressed in the *Energy and Regulatory Boards Act*:

Powers and duties

5 (1) The Energy Board has those functions, powers and duties that are conferred or imposed upon it

(a) by this Act;

(b) by the *More Access to Energy Act*;

(c) respecting the production, transmission, delivery or furnishing of electrical energy for the purpose of heat, light and power or steam heat, geothermal heat, geothermal resources and electricity efficiency and conservation, by the *Public Utilities Act*;

(d) by the *Gas Distribution Act*, the *Electricity Act*, the *Petroleum Products Pricing Act* or any other enactment; and

(e) as the Governor in Council prescribes by the regulations.

(2) The Governor in Council may assign to the Energy Board the powers, functions and duties of any board, commission or agency and while the assignment is in effect, that board, commission or agency is discontinued and Section 43 applies with necessary changes respecting that board, commission or agency.

Approving and fixing rates, regulatory powers

6 (1) In approving or fixing just and reasonable rates, tolls, charges or tariffs pursuant to this Act or any other enactment, the Energy Board may adopt any method or technique that it considers appropriate, including an alternative form of regulation.

(2) In approving or fixing rates, tolls, charges, tariffs, capital applications and all other matters over which the Energy Board has authority, the Board shall give appropriate consideration to the extent to which such rates, tolls, charges, tariffs, capital applications or other matters

(a) support competition and innovation in the provision of energy resources in the Province;

(b) support the development of a competitive electricity market;

(c) ensure the provision of safe, secure, reliable and economical energy supply in the Province;

(d) support sustainable development and sustainable prosperity; and

(e) support such other factors as prescribed by the regulations,

with the goal of approving rates, tolls, charges, tariffs, capital applications or other matters that are consistent with the purpose of this Act, the *More Access to Energy Act* and the regulations.

(3) Subject to subsection (4), the Energy Board shall regulate

(a) the Independent Energy Systems Operator, transmitters and all matters relating to public utilities that perform the functions of production, transmission, delivery or furnishing of electrical energy to or for the public for the purpose of heat, light and power, geothermal resources, geothermal energy, geothermal heat or steam heat;

(b) the franchise holder granted a franchise pursuant to Section 79C of the *Public Utilities Act*;

(c) the Halifax Water district energy project;

(d) any holder of the franchise to construct and operate a gas delivery system in the Province pursuant to the *Gas Distribution Act*; and

(e) any other entity or service prescribed by the regulations.

(4) The Governor in Council may make regulations

(a) prescribing factors for the Energy Board to consider when approving rates, tolls, charges or tariffs, capital applications and all other matters over which the Energy Board has authority respecting the production, transmission, delivery or furnishing of electrical energy for the purpose of heat, light and power or steam heat, including combined heat and power;

(b) excluding any entity or service from the jurisdiction of the Energy Board.

(5) The exercise by the Governor in Council of the authority contained in subsection (4) is a regulation within the meaning of the *Regulations Act*.

(6) The Energy Board shall endeavour to issue fair decisions in relation to all matters in a manner that is efficient, effective and as timely as possible.

(7) The Energy Board shall make public all approved rates, tolls, charges, tariffs and capital applications on its website and update these documents as required.

...

Jurisdiction of Board

30 (1) A Board has exclusive jurisdiction in all cases and in respect of all matters in which jurisdiction is conferred on the Board.

(2) The Boards, as to all matters within their jurisdiction pursuant to this Act, may hear and determine all questions of law and of fact.

[29] Public utilities tend to be natural monopolies. As such, the impact of competitive forces on those entities may be muted or non-existent. In the absence of these forces, the Board's ratemaking function is designed to allow the utility to recover its legitimate costs of providing service and an opportunity to earn a reasonable profit at rates that are fair for its customers. This ratemaking function has been described by the Nova Scotia Court of Appeal as a surrogate for competition and not a tool for implementing social policy:

[32] The Board sets rates for a utility that has a virtual monopoly on the supply of electric power. The Board's decision discusses this process: (2005 NSUARB 27)

[17] ... NSPI is not like an unregulated retailer. It is a virtual monopoly which operates its business on a cost-of-service basis. Providing electricity to all communities in the Province was not (and likely still is not) financially feasible for private, competitive companies. For that reason, the Province's electric service supplier is a cost-of-service monopoly. In return for undertaking and continuing the costs of electrification of the Province, the utility is permitted, under the **Act**, to recover the reasonable and prudent costs of providing the service. Because it is a monopoly, regulation operates as a surrogate for competition. One of the regulator's tasks is to balance the need for the Utility to recover its reasonable and prudent costs with the need to ensure that ratepayers are charged fair and reasonable rates.

[18] It is in the interests of all Nova Scotians to ensure that NSPI continues to be a stable and financially sound company. This is a reality which the Board must consider when determining what, if any, rate increase is warranted.

[19] In short, rates charged to customers are based on costs incurred by the Utility in providing service. If the Board finds certain costs to be imprudent or unreasonable, it can (and has) disallowed such expenditures and reduced proposed rate increases accordingly.

[33] I agree with this portrayal of the background to the Board's rate-making function. The Board's regulatory power is a proxy for competition, not an instrument of social policy.
[Emphasis added]

[*Dalhousie Legal Aid Service v Nova Scotia Power Inc.*, 2006 NSCA 74]

[30] As noted already, the Board's powers are defined by legislation. Section 45 of the *Public Utilities Act*, RSNS 1989, c 380 (*PUA*) requires the Board to use a cost-of-service methodology to set rates and entitles the utility to a just and reasonable return:

Amount utility entitled to earn annually

45 (1) Every public utility shall be entitled to earn annually such return as the Board deems just and reasonable on the rate base as fixed and determined by the Board for each type or kind of service furnished, rendered or supplied by such public utility, provided, however, that where the Board by order requires a public utility to set aside annually any sum for or towards an amortization fund or other special reserve in respect of any service furnished, rendered or supplied, and does not in such order or in a subsequent order authorize such sum or any part thereof to be charged as an operating expense in connection with such service, such sum or part thereof shall be deducted from the amount which otherwise under this Section such public utility would be entitled to earn in respect of such service, and the net earnings from such service shall be reduced accordingly.

(2) Such return shall be in addition to such expenses as the Board may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the Board according to this Act and the rules and regulations of the Board. [Emphasis added]

[31] In legislation, the word "shall" is mandatory. However, the phrases "just and reasonable" and "reasonable and prudent" allow the Board to exercise some discretion. Additionally, the Board's mandate under the *PUA* encompasses a significant public interest component (*Nova Scotia (Attorney General) v Nova Scotia (Utility and Review Board)*, 2019 NSCA 66, paras 113-116). But as considered above, the Board's implicit powers are tied to the purposes of the statute.

[32] The Nova Scotia Supreme Court, Appeal Division decision in *Nova Scotia (Public Utilities Board) v Nova Scotia Power Corporation*, (1976) 18 NSR (2d) 692 (the *Contracts Case*) is often referenced for its consideration of the scheme of regulation under the *PUA*:

17 The scheme of regulation established by the Act envisages and indeed compels control by the Board of all aspects of a utility's operation in providing a controlled service. Two great objects are enshrined - that all rates charged must be just, reasonable and sufficient and not discriminatory or preferential, and that the service must be adequately, efficiently and reasonably supplied to the public. Almost all provisions of the Act are directed toward securing these two objects - that a public utility give adequate service and charge only reasonable and just rates.

18 The service requirement is expressed in s. 48, as follows:

48 Every public utility is required to furnish service and facilities reasonably safe and adequate and in all respects just and reasonable.

... 20 Rates must be "just" (s. 41) and must not be "unreasonable or unjustly discriminatory" (s. 18 and s. 78(1)), or "unjust, unreasonable, insufficient or unjustly discriminatory, or . . . preferential" (s. 82(1)). The "justness" of rates has two aspects - rates of a utility as a whole must be "reasonable" and just for the public it serves and just and "sufficient" for the utility itself - and the rates for the various customers or classes of customer of a utility must not as between each other be "unjustly discriminatory" or "preferential".

21 The control of the over-all level of rates has its keystone in s. 42(1) which states:

42 (1) Every public utility shall be entitled to earn annually such return as the Board deems just and reasonable on the rate base as fixed and determined by the Board.

...

23 The concept of a utility securing a reasonable return on its rate base automatically makes specific the apparently vague standard that rates be "just". The utility's economic health and its ability to supply adequate service and to finance capital expansion are assured by giving it a "just and reasonable" return. Overall rates must thus be sufficient to produce that return after allowing operating expenses and other "just allowances" (s. 42(2)). The rates must thus be "sufficient" to produce that return, no less and no more.

24 The public interest charges the Board with the duty of ensuring no extravagance by a utility in either capital or operating expenditure. The rate base is to include only assets "used and useful" in providing service (s. 29 (1)). Additions to it are controlled by the requirement that Board approval be secured for any new construction project of more than \$5,000 (s. 34 as amended). The expenses for rate-making purposes are only those the Board allows "as reasonable and prudent and properly chargeable to operating account" (s. 42(2)). Other "just allowances" are prescribed by the Act and Regulations, e.g. annual depreciation charges (ss. 35-38).

...

26 The Board has on occasion summarized its duty in terms which, accurately I believe, emphasize the comprehensive nature of its control of the rates and services of a utility. Its decision of February 25, 1970, in respect of an application of Maritime Telegraph and Telephone Company Limited, contains the following at p. 25 of the Board's Report for 1970:

A public utility is obligated to provide services that are reasonably safe and adequate and is entitled to compensation therefor by the charging of rates

that are not unjustly discriminatory and will provide the public utility with sufficient revenue to enable it to pay its operating expenses including depreciation and income taxes, and have net earnings sufficient to enable it to obtain and service normal and needed capital requirements. It is expected to meet reasonable demands for additional services and to conduct its affairs with efficiency. When an application is made to this Board for approval of revisions in rates, tolls and charges designed to produce additional revenue the public utility is required to produce evidence showing the needs and purposes for which such additional revenue is required. And upon any such application the Board inquires into and examines the adequacy and reasonableness of existing services, the efficiency of the public utility, the nature and extent of the needs and purposes upon which the application is grounded and the propriety of the proposed rate changes.

27 The "propriety" of the rates involves not only the propriety of their over-all level as adjudged by rate base return, but also their propriety for the various classes of customer. The Board's twofold duty is to ensure that the rates as a whole are reasonable and that they are reasonable to all customers *inter se*. This latter aspect of its duty is imposed by the various provisions prohibiting unjust discrimination and requiring equal rates in substantially similar circumstances. [Emphasis added]

[33] In exercising its ratemaking function, following the statutory requirements and mindful of the purposes of the legislation, the Board is also guided by the following long-established, fundamental ratemaking principles, which the NSUARB noted in its decision for NS Power's rate application in 2002 and a number of rate applications since:

[21] In utility regulation, there are generally accepted principles which govern the rate-making exercise. The object of rate-making under a cost-of-service-based model is that, to the extent reasonably possible, rates should reflect the cost to the utility of providing electric service to each distinct customer class. In regulating NSPI, the Board is guided by these generally accepted principles as well as by case law.

[22] A widely-accepted publication written by Dr. James Bonbright entitled **Principles of Public Utility Rates**, sets out the following guidelines for determining appropriate rates:

CRITERIA OF A SOUND RATE STRUCTURE

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.

8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
 - (a) in the control of the total amounts of service supplied by the company;
 - (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).(Exhibit N-92) (James Bonbright, **Principles of Public Utility Rates**, Columbia University Press, 1961, p. 291)

[23] These principles are well established and form the background against which the current application must be assessed.

[2002 NSUARB 59, paras. 21-23]

[34] The principles of statutory interpretation apply in determining the intent of any particular statute, including in the Board's interpretation of the statutory provisions in the *Public Utilities Act*, and other legislation relevant to this matter, to determine the scope of the powers conferred upon the Board.

[35] As discussed in the reasons of the majority in the Supreme Court of Canada's decision in *Canada (Minister of Citizenship and Immigration) v Vavilov*, 2019 SCC 65, administrative decision makers are required to consider the text, context and purpose in interpreting legislation. The Board must also have regard to the *Interpretation Act*, RSNS 1989, c 235.

3.0 ANALYSIS AND FINDINGS

3.1 Should the Settlement Agreement be Approved?

[36] On September 2, 2025, NS Power wrote to the Board to advise that it would be filing a general rate application for the 2026 and 2027 test years. It stated that it had reached a consensus with the customer representatives which was the "result of an extensive collaborative process involving NS Power and customer representatives and it is being filed with the support of those representatives for the outcomes of the GRA".

However, it did not file its general rate application until September 18, 2025. NS Power only filed the settlement agreement on November 5, 2025, when asked to do so in information requests (IRs) by Board staff.

[37] The terms of the settlement agreement are set out in a schedule to the agreement and provide as follows:

GRA Element	Settlement Terms
Rates	a) Rates are proposed to be effective January 1, 2026 and the Parties will make all reasonable efforts to facilitate and support a process that will result in this outcome. b) Subject to the terms set out herein being fully incorporated into the 2026-2027 GRA, the average rate increase across all customer classes (inclusive of non-fuel and Base Cost of Fuel costs) is anticipated to be approximately 2.1% in 2026 and 2.1% in 2027.
Depreciation	a) The Parties agree to reduce depreciation rates in accordance with Appendix "A" in order to achieve a reduction in depreciation and accretion expense of approximately \$20M/year over the 2026-2027 test period, as compared to the depreciation rates included in the Draft GRA.
O&M	a) The Parties agree to the operation and maintenance expense amounts included in the Draft GRA, subject to the reductions in O&M set out in the attached Appendix "B".
Storm Cost Recovery Rider	a) The Storm Cost Recovery Rider will be implemented as described in the Draft GRA, subject to the following: (a) the Storm Cost Recovery Rider will not be implemented on a permanent basis as proposed, rather it will continue on a pilot basis with costs in 2026 and 2027 eligible for the rider; and (b) the threshold for making an application to return an

GRA Element	Settlement Terms
	underspend to customers will be changed from \$5 million to \$2.5 million.
Cost of Capital and Earnings Band	a) An overall return on equity of 9% for rate setting purposes retained, as well as an earnings band of 8.75% to 9.25%.
Capital Structure	a) An equity thickness of 40% for rate setting purposes will be retained.
DSM Rider	a) The DSM Rider will be amended as set out in Appendix “C”. NS Power will make best efforts to negotiate necessary revisions to its Supply Agreement with EfficiencyOne, if any, or otherwise bring such revisions forward in the relevant proceeding to ensure that the End of Approved DSM Term Adjustment is implemented for the 2023-2026 term.
Weather Normalization Mechanism	a) The request for approval of a Weather Normalization Mechanism will be removed; however, the parties agree to participate in an information session to gain a better understanding of Weather Normalization Mechanisms.
Cost of Service (“COS”)	a) The COS as set out in the Draft GRA will be included in the 2026-2027 GRA and put forward for approval, subject to the following: (a) use of the Minimum System methodology after the 2026-2027 test period will be subject to a future proceeding and determination by the Board, for which an application will be made in 2026 and in which parties are free to take any position they so choose; (b) NS Power will collect and disclose the data outlining the extent to which PHP uses, relies upon and/or benefits from the High Voltage transmission system and in any proceeding to determine rates for PHP after the 2026-2027 test period, Parties may make submissions regarding the extent to which PHP is to be responsible for any costs of the High Voltage transmission system; and (c) the appropriate apportionment of assessment costs from the Maritime Link as between generation and transmission will remain open to be addressed as Parties see fit in any proceeding to determine rates after the 2026-2027 test period.
MEU Treatment	a) The MEUs will be included as taking service under the Municipal Tariff in calculating the Municipal Tariff rates for the 2026-2027 GRA and the MEUs commit to taking partial service under the Municipal Tariff in the years 2026 and 2027 .

GRA Element	Settlement Terms
	<p>b) NS Power and the MEUs will work collaboratively and in good faith to determine and attempt to agree, by no later than December 1, 2025 on (1) the timeline by which the MEUs will pay NS Power the full amounts of outstanding fuel costs and Maritime Link Assessment costs, and (2) the implementation of the BUTU Tariff service arrangements in conjunction with service under the Municipal Tariff in 2025, 2026, and 2027.</p>
OATT	<p>a) In calculating the OATT rate, NS Power will cap the contribution of Wreck Cove to the 32 MW Spinning Reserve requirement in the calculation of the rate for Spinning Reserve service.</p> <p>b) The 2-standard deviation methodology will be used for ratemaking purposes for the load following requirement.</p> <p>c) For the 2026-2027 GRA period, the costing approach will utilize 50 percent of the estimated average hourly demand of LIIR interruptible load as 10-minute operating reserve on a day ahead basis.</p>
PHP Treatment	<p>a) NS Power’s 2026/2027 cost of service study includes PHP as an above-the-line customer based on the forecast of receiving Board approvals for a new PHP tariff in time to implement for January 1, 2026.</p> <p>b) The COS has been prepared on the basis of the following PHP load characteristics: a) PHP’s firm load at 8MW at the three coincident peaks; b) PHP’s firm, plus interruptible load, at a forecast of 65 MW based on prior actual PHP metered load at the time of NSP’s 3CP; and c) PHP energy will be based on PHP’s forecast usage for the test years, net of the amount forecast to be provided by the Goose Harbour Lake Wind Farm. The same load characteristics are applicable to the base cost of fuel model as well.</p> <p>c) The dollar value of the Interruptible credit to be applicable to PHP’s interruptible load shall be the same as the credit for Large Industrial Interruptible customers, plus the value of priority interruption service provided, if any. The priority interruptibility service that may be provided by PHP is modelled at an additional 10% credit.</p> <p>d) PHP and NS Power will complete discussions and analysis of the value of Active Demand Control (“ADC”), which shall be proposed to be a rider to the cost-based rate. The value of ADC, and the proposal for cost recovery, if any, shall be</p>

GRA Element	Settlement Terms
	<p>brought forward for approval by the Board later this year to be effective January 1, 2026. For clarity, any payment approved by the Board for Active Demand Control services will be collected from above the line customers.</p> <p>e) NS Power and PHP shall reflect the foregoing in a written tariff which shall also include a proposal for priority interruptibility to be brought forward for approval by the Board later this year to be effective January 1, 2026 and PHP commits to taking service under such a tariff on January 1, 2026, or such later date as the Board approves the tariff as being effective, whether on a permanent or interim basis, subject to satisfactory conclusion of the resolution of the PHP ADC and tariff processes.</p> <p>f) In the PHP ADC and tariff processes that will be brought forward for approval by the Board later this year, it remains open for all Parties to take any position they so choose, including whether each of the PHP ADC and tariff filing(s) is inconsistent with the load characteristics and basic tariff structure as set out above.</p> <p>g) NS Power may seek Board approval for a deferral account to account for any NS Power revenue variances that may arise in 2026 or 2027 from the following scenarios, which costs would be collected/refunded from/to above the line customers: (a) where a Board decision on the PHP tariff, including the Active Demand Control Rider, differs from the above the line PHP tariff assumptions included in the 2026-2027 GRA; (b) where, for any reason, the PHP tariff is not available for PHP to take service under it as of January 1, 2026; and/or (c) PHP determines the PHP ADC and tariff processes outcome is not satisfactory.</p>
Securitization	<p>a) NS Power will make best efforts to finalize and apply prior to January 1, 2026 for approval of its proposed securitization of assets, cost of service treatment and the Securitization Rider. It remains open for all Parties to take any position they so choose in relation to such an application.</p>
ML Transmission Assets	<p>a) Inclusion of CI 43324, CI 43678, CI 45066, and CI 45067 in rate base, subject to the Board being satisfied that the threshold test it articulated in paragraph 405 of its decision in M10431 has been met.</p>

GRA Element	Settlement Terms
EIFEL	a) If the excessive interest and financing expenses limitation (“EIFEL”) exemption is not enacted, the Parties agree to defer the incremental tax expense over the 2026-2027 GRA period, which is anticipated to be approximately \$7.5 million.
NS Power Future Deliverables	a) Within a reasonable amount of time following the execution of this Settlement Agreement, NS Power will provide: (a) confirmation that radial to generation lines being allocated to the generation function do not also serve any load; and (b) the methodology that NS Power is proposing to functionalize storage assets.

[Exhibit N-27, NSEB IR-1, pp. 9-13]

[38] Previous decisions by the NSUARB set out the principles it applied in its consideration of settlement agreements. Those principles are still relevant and bear repeating. In its decision dated November 5, 2008, about a prior NS Power general rate application, the NSUARB 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 if 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]

[39] The Board remains mindful that in its consideration of settlement agreements its ultimate duty is to ensure that the terms of the 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 honored.

[NS Power 2007 GRA decision, 2007 NSUARB 8]

[40] The Board agrees with the following submission in the NSUARB's 2023-2024 GRA Decision about the important role of settlement negotiations in such proceedings:

... It is in the public interest to approve settlement agreements in these circumstances in order to encourage a collaborative approach to ratemaking. Doing so provides incentive to parties to be reasonable and promotes the reduction of controversy in rate applications coming to the Board.

[Board Decision, M10431, para. 60]

3.1.1 Findings

[41] As noted above, the NSUARB has considered settlement agreements in past matters. The Board appreciates the efforts of parties to resolve contested issues in matters coming before it and encourages such initiatives to continue. Notwithstanding

that, the Board reiterates that its ultimate duty in considering settlement agreements is to ensure that the terms of such agreements are just, reasonable and in the public interest. As part of this exercise, the Board must ensure that “only those costs which are fair, justifiable and prudently incurred” by the utility are ultimately approved.

[42] There is no doubt that a settlement agreement between the utility and most of its customer classes should attract significant weight. The Board recognizes that significant efforts were called upon in canvassing the complex myriad of issues that were ultimately concluded in their settlement. The Board is mindful that the discussions and negotiations involved compromises by all parties in the final result. The customer representatives actively participate in numerous NS Power proceedings before the Board. The Board recognizes that by negotiating a settlement agreement, parties tried to reduce hearing costs and achieve some certainty over the results.

[43] However, there is a distinction between what occurred in prior general rate applications and what transpired in the current proceeding. Previously, settlement agreements were concluded after an extensive evidentiary record had been filed with the Board, including many information requests and evidence filed by intervenors (among them the very customers who signed a settlement agreement) and Board Counsel consultants. In the current matter, the settlement agreement was concluded even before the application was filed. While this does not negate the efforts of the parties to reach a settlement, the Board concludes that it is a factor that affects the weight it assigns to the settlement agreement. The agreement is still entitled to some deference but, given the circumstances, it does change the Board’s perspective on the settlement. It does not have the full benefit of the parties’ views of the application, and the value assigned to various

compromises reached in achieving a negotiated settlement. In some instances, the Board was left uncertain about whether certain perspectives had been analyzed or considered. Further, the Board does have the benefit of having the evidence of the Board Counsel consultants, who did not participate in the settlement discussions but were able to conduct an independent review of the application.

[44] A general rate application is a very complex proceeding which raises a multitude of difficult issues. The Board is left with the very difficult duty to ensure that the terms of the settlement agreement are just, reasonable and in the public interest. Following its review, the Board finds that the settlement agreement does contain many terms that are appropriate and should be adopted. However, the Board also concludes that some amendments to the application, as described in the remainder of this decision, are required to ensure just and reasonable rates.

3.2 Fuel and Purchased Power

[45] Fuel and purchased power expenditures are direct pass-through costs paid by NS Power's customers. Under the Fuel Adjustment Mechanism (FAM), those costs are identified as the Base Cost of Fuel (BCF). Actual fuel and purchased power costs will be tracked, but actual costs will differ from forecast costs. Any over or under recoveries will be refunded or collected through the FAM Actual Adjustment (AA) and Balance Adjustment (BA) riders. Throughout each year, NS Power provides monthly, quarterly and annual updates of its fuel costs and the recoveries from customers. In addition, an independent auditor appointed by the Board conducts fuel cost audits every two years and those audits are reviewed in public regulatory proceedings.

3.2.1 Base Cost of Fuel

[46] Fuel and purchased power costs comprise the largest portion of NS Power's revenue requirement. During the two-year test period, NS Power has forecast those costs to be \$918.6 million for 2026 and \$918.4 million for 2027. This represents about 47.4% and 46.1% of the annual revenue requirements, respectively.

[47] However, in this application NS Power is seeking approval of new BCF amounts of \$927.3 million for 2026 and \$850.9 million for 2027. With those BCF adjustments, NS Power proposes to smooth the overall increases (combined BCF and non-fuel rates) for each rate class during the 2026-2027 GRA period. This results in setting rates that over-collect fuel costs in 2026 but under-collect in 2027.

[48] Board Counsel engaged a consultant, Bates White, to review NS Power's fuel and purchased power costs, which included the BCF, load forecast report, the accuracy of NS Power's commodity price forecasts, and determining whether the NS Power application adequately represents the fuel component.

[49] As seen in Figure 5-2 below, based on the two-year BCF forecast, NS Power applied for an average annual increase in FAM customer rates of 2.3% in 2026 and a reduction of 1.7% in 2027. Bates White noted that in contrast with the 2023-2024 GRA, NS Power did not include any files supporting the AA/BA calculations. When asked in NSEB IR-36 about the anticipated rate impacts from the AA/BA, NS Power stated that it did not complete the rate impact analyses, but those details would be provided in the FAM AA/BA application anticipated to be filed prior to the end of 2025. The AA/BA amounts are subject to revision and finalization during a separate regulatory proceeding near the end of each year. On December 18, 2025, NS Power applied to the Board to extend the existing AA/BA riders on an interim basis, effective January 1, 2026, pending

a decision in this GRA and a subsequent AA/BA application which it intended to file in January 2026. The Board granted that request in Matter M12640 on December 23, 2025.

Figure 5-2 – 2026-2027 Fuel Rate Percentage Changes with Smoothing

Customer Class	2026	2027
Residential	1.2	(0.4)
Small General	2.7	(0.8)
General	3.5	(3.2)
Large General	3.8	(5.7)
Industrial		
Small	4.7	(3.3)
Medium	3.8	(6.7)
Large Industrial		
Firm Transmission Service	4.1	(6.6)
Firm Distribution Service	3.9	(6.3)
Interruptible Transmission Service	4.9	(8.0)
Interruptible Distribution Service	4.5	(7.5)
Large industrial Total	4.6	(7.6)
Municipal	9.6	(0.4)
Unmetered	(0.7)	2.8
Total	2.3	(1.7)

[Exhibit N-3, p. 28]

[50] In its response to Bates White IR-10, NS Power stated that it is forecasting a FAM liability of \$10.2 million at the end of 2026 and \$0.8 million at the end of 2027. NS Power also stated that at its weighted average cost of capital (WACC), the FAM deferral will incur interest expense of \$1.0 million in 2026 and \$1.3 million in 2027.

[51] In assessing whether NS Power has adequately represented the fuel and purchased power component in the application, Bates White noted that in some cases, NS Power was unable to provide all requested data due to a cybersecurity incident which made data retrieval impossible. However, Bates White stated that NS Power used

reasonable, publicly available forecasts of prices for fuels, including natural gas, coal, and heavy fuel oil, as well as purchased power.

[52] Although Bates White considered that the forecasts appeared reasonable, they noted those forecasts were dated. NS Power used PLEXOS, a commercially available hourly economic dispatch model, to forecast its fuel and purchased power consumption over the 2026-2027 period. In its evidence, Bates White stated:

The original PLEXOS forecast was run in November 2024 using a 30-day average of prices as of October 29, 2024. In March 2025, following receipt of the Sulphur Dioxide ("SO₂") Certificate of Variance ("CoV"), the forecast was rerun. The results of the March 2025 run were used in the September 2025 filing.

NSPI's decision to use the October 29, 2024 commodity price forecasts is likely reasonable, given that NSPI has reached settlement with several parties and that FAM costs are included in the Settlement Agreement. Using more updated commodity price forecasts would be optimal, given that more updated forecasts would represent the best and most updated expectations of fuel and purchased power prices in 2026 and 2027, but we acknowledge NSPI's point that updating rates could upset the Settlement Agreement. Still, using a more updated forecast could be warranted if there were major changes in the forecast of either energy [or] demand for the 2026 or 2027 period.

... some commodity price movement has been observed since the time of the GRA commodity price forecasts (October 2024). Monthly coal futures for the 2026-2027 period, as measured by the API-2 index, are lower by an average of 2.8%. Monthly natural gas price futures, as measured at Henry Hub, are higher by an average of 12.4%.

... Given the timing of the settlement discussions, NSPI's reliance on commodity price forecasts from October 29, 2024 appears reasonable, despite some moderate movement in commodity price forecasts. We observe no major changes regarding commodity futures prices that would require an update to the rates, which could potentially negatively impact the nature and status of the Settlement Agreement reached by the parties in this proceeding. [Emphasis added]

[Exhibit N-35, pp. 14-15]

[53] In reviewing NS Power's load forecast, Bates White noted that the GRA forecast was an update to NS Power's 2024 Load Forecast, and the 2026 and 2027 GRA represented settlement agreement outcomes based on rates developed in 2024 and early 2025, before the 2025 Load Forecast Report was issued. Bates White also stated:

NSPI's decision to use the September 2024 GRA Forecast is reasonable. The GRA Forecast uses the same methodology as the Board-approved 2024 Load Forecast and provides an interim update of energy demand and peak load in its settlement discussions with customer representatives. Using the 2025 Load Forecast data would be optimal, given that the 2025 Load Forecast represents the best and most updated expectations of energy

[and] demand in 2026 and 2027, but we acknowledge NSPI's point that updating rates could upset the Settlement Agreement. Still, using a more updated forecast could be warranted if there were major changes in the forecast of either energy [or] demand for the 2026 or 2027 period.

... The GRA Forecast expectations for energy demand in 2026 and 2027 is within 1% of the forecast values for both the 2024 and 2025 Load Forecasts.

... Given the timing of the settlement discussions, NSPI's reliance on the September 2024 GRA Forecast appears reasonable, and we observe no major changes between the 2024 and [sic] GRA Load Forecasts and the 2025 Load Forecast that would warrant an update to the rates, which could potentially negatively impact the nature and status of the Settlement Agreement reached by the parties in this proceeding. [Emphasis added]

[Exhibit N-35, pp. 33-35]

[54] During the hearing, NS Power was asked about the amount included in its revenue requirement for the NSP Maritime Link Inc. (NSPML) assessment relating to the interest and principal for repayment of the \$500 million Federal Loan Guarantee (FLG). NS Power included \$41.5 million for 2026, but a subsequent NSPML application identified that cost to be \$1.8 million lower at \$39.7 million. The cost included in its 2027 revenue requirement may also be inflated by a similar amount:

Q. So in this case, it refers to Appendix 5A and it says:

On page 34 of Appendix 5A, the application states that NSPML's forecast assessments for the Maritime Link against Nova Scotia Power are \$200.5 million in 2026 and \$203.9 million in 2027 (including \$41.5 million and \$40.6 million for ['26 and '27 to pay the] interest and principal on the... Federal Loan Guarantee.

So in relation to the federal loan guarantee portion of it, I note -- and you can take it subject to check, hopefully -- that we currently have an assessment before the Board, the 2026 NSPML assessment, and instead of the 200.5 million assessment in '26, the actual request was 198.7, which is a difference of 1.8 million. And one of the major differences in that is that the amount included for the federal loan guarantee, instead of being 41.5 million, was actually 39.7. So it was actually almost a difference of 2 million there.

And so -- and because that balance will be reducing -- well, the balance they had, 39.7 for 2026, is already lower than what you had projected for -- or what was in the Application for 2027. So it's 1.8 -- the actual assessment, if it's approved, will actually be - - and probably won't be higher than that. It might be lower. But the assessment would be at least 1.8 million less than what's in your base cost of fuel. And I suspect that the same would happen for 2027. So that's 2 million over two years.

I'm just wondering whether the -- I don't know -- I've gone through the '26 assessment. I haven't found a reference to what a projected '27 assessment would be, but I suspect it's pretty close. So that would be 2 million over two years.

Is there some way we could -- I could ask you for an undertaking if you could check with NSPML what their projection is for at least the federal loan guarantee part and we could take that difference. But that's \$2 million right there off of both years on the base cost of fuel.

So I'm just -- do you have any comment or solution in terms of adjusting the base cost of fuel for those amounts?

And I suspect there's a schedule -- I just couldn't put my hand on it -- for the federal loan guarantee, but I know they're going down. You're paying less every year. So I suspect it's probably low 39 to approximately high 38 million for '27.

A. (Willett) I can't speak to the 2027 latest projection. But what I would mention is these estimates were obviously taken at a point in time and to the best estimates at that time, just like any ---

Q. Oh, I agree.

A. (Willett) --- commodity or just like coal, the numbers will fluctuate, and the AA/BA process is there to true those up, so customers only pay the actual cost of the assessment and the FLG.

The other item, just to note as well, with rates not going into place January 1, those rates currently are set below cost so there will be or there is expected to be under-recoveries until those rates are in place to match the true cost. So those items will be trued up through the AA/BA, but we will be seeing under-recovery of -- until those rates are in place for the base cost of fuel.

Q. Right. Except that we know the 200.5 million is not a projection any more. It's actually -- for '26, it's only 198.7. So we know that number.

It's not a projection any more. We actually know it. Two million dollars, you know, is \$2 million over two years would be -- you know, it's \$4 million.

A. (Williams) Mr. Deveau, if I may -- and I agree. So in terms of the volatility discussion, volatility, uncertainty until you've -- you've got certainty, which with commodities very rarely do you ever get certainty until you've actually made the purchase, whereas with this there is certainty in terms of the price.

I think more to the point, though, is the \$2 million difference that you're speaking to will not actually be \$2 million because, as Mr. Willett was indicating, rates won't be in effect as of January 1, 2026. So you'll have that shortfall that will need to be made up in any event. So the \$2 million is likely made up as a result of that regardless.

Q. Right. This is not a commodity, though. These are costs.

A. (Williams) No, agreed...

[Transcript, January 9, 2026, pp. 840-845]

[55] In its closing submissions, Renewall Energy Inc. (REI) raised a concern with the accuracy of NS Power's fuel forecasts. REI noted that average fuel cost forecasts in each of the past five years were significantly lower than actual costs, and that increased

accuracy is essential for encouraging competition in Nova Scotia, as well as to avoid interest on fuel cost deferrals. REI further stated:

This means that NSPI's customer rates have been lower than required in each of the last 5 years. If NSPI's retail rates are consistency [sic] lower than needed to recover the appropriate revenue, it creates an unfair market condition for retail competition in two ways. It sets an unrealistic benchmark of posted retail rates for comparison purposes, and it creates an ongoing fuel liability for customers looking to leave NSPI bundled service.

...

REI respectfully requests that the Board direct NSPI to establish more accurate fuel cost forecasts, and to follow the FAM POA that outlines that fuel cost overages from one year be recovered in the following year (rather than deferred over multiple years)...

[REI Closing Submissions, p. 5]

[56] On pages 28-29 of its reply submissions, NS Power responded to REI's concern:

NS Power submits that no such directive is warranted or necessary. The Plan of Administration (POA) outlines the approved process for forecasting of fuel and purchased power expenses. As the Board is aware, NS Power is audited bi-annually by the Board-appointed Fuel Adjustment Mechanism (FAM) Auditor, Bates White. The Auditor specifically evaluates and opines on the Company's adherence with the POA. Further, as noted in the Company's closing submission, Bates White submitted evidence in this proceeding on behalf of Board Counsel and indicated that NS Power used reasonable methods and resources in its forecast of fuel and purchased power costs included in this GRA.

3.2.1.1 Findings

[57] The Board notes that NS Power's proposed BCF was deemed acceptable to customer representatives who signed the settlement agreement. The Board also notes Bates White's statements that, although the commodity prices and load forecast used by NS Power were dated, they were reasonable. Bates White said they did not observe any major changes regarding commodity futures prices that would require an update to the fuel rates, nor did they observe any major changes between the 2024 GRA Load Forecast and the 2025 Load Forecast that would warrant an update to the rates.

[58] As noted above, the cost included in NS Power's Base Cost of Fuel for NSPML's 2026 assessment is about \$1.8 million greater than the FLG interest and principal amount identified by NSPML in its recent 2026 assessment application. In its compliance filing, NS Power is directed to remove that additional \$1.8 million from its revenue requirement for 2026. NS Power is also directed to obtain an updated amount for the FLG interest and principal from NSPML for 2027 and remove any excess amount that was included in its 2027 revenue requirement.

[59] On the issue raised by REI, the Board recognizes that a pattern of actual fuel costs being higher than forecasted could present some challenges to participants in the Renewable to Retail market. NS Power's forecasts and results are reviewed by parties during related proceedings and by the Board's fuel auditor to identify any errors or inaccuracies. Despite those reviews, it is incumbent upon NS Power to continually refine its forecasting to minimize cost variances and the impact on customers and market participants. The Board expects NS Power will continue to work towards that objective.

3.2.2 FAM Plan of Administration and Fuel Manual

3.2.2.1 Plan of Administration

[60] In its application, NS Power requested approval of amendments to the FAM Plan of Administration as described in Section 6 and Appendix 6A and set out in Appendix 6B. On page 32 of the application, NS Power listed the proposed changes:

Requested changes to the FAM Plan of Administration (POA) for the 2026-2027 GRA Period are described in **Appendix 6A** and set out in **Appendix 6B** (Redline and Clean versions). Proposed changes to the POA include cost of service changes to fuel costs to align with NS Power's COSS, the addition of customer renewable program credits (community solar energy credit rider) as an allowable fuel cost, the change related to the migration of customers to and from the FAM classes (as set out in section 13.10 [*sic*] below), and movement of some costs previously included in OM&G expenses to the FAM. There are also administrative changes to the main document to reflect the GRA period and a request to discontinue Appendix D, the calendar of FAM-related filings and events during the GRA Period. The dates for filings are set by the NSEB, and the FAM Small Working Group sessions are set a year in advance by NS Power. The timetable of events is no

longer a useful part of the POA, as all the deadlines (except FAM Small Working Group meetings) are prescribed in the POA main document.

[Exhibit N-3, p. 32]

[61] Regarding the proposed amendment to include costs associated with renewable energy programs in s. 3.2.8 of the Plan of Administration (POA), NSEB IR-33 requested comment on the appropriateness of including certain additional language in the proposed change. In its response, NS Power stated that adding “*when such costs cannot be recovered from program participants*” to part b) is helpful clarification which aligns with the underlying intent of that provision.

[62] In its response to NSEB IR-34, NS Power elaborated on some of the OM&G expenses proposed to be moved to the FAM, which were previously identified in its 2023 application to revise the POA (M11127). In that matter, the Board indicated that those OM&G costs could be given consideration for movement to the FAM during a subsequent GRA.

[63] In addition, NS Power noted that the Board’s Decision and Order in the 2024 FAM AA/BA proceeding directed it to amend the FAM Tariff to account for both customers moving out of the FAM class and back into the FAM class since the previous FAM Tariff was only amended to account for customers moving out of the FAM classes. NS Power stated that it has amended Special Condition 3 of the FAM Tariff, included in PR-01 Attachments 1s and 2s, and Section 3.1 of the Plan of Administration as set out in Appendix 6B.

3.2.2.2 Fuel Manual and Hedging Plan

[64] On page 29 of its application, NS Power stated:

NS Power’s currently approved version of the Confidential Fuel Manual, which sets out the requirements for fuel and purchased power procurement, is included in Standardized Filing **OE-01F** and the Hedging Plan with a minor language change is included in **Appendix 5B**. The language of the preamble to Appendix Q (which is an overview of the Hedging Plan)

in the Fuel Manual has been updated to refer to the plan in a generic way, rather than referencing specific years and filings which need to be updated. This is an administrative change only and does not affect the substantive content of the Fuel Manual or the Hedging Plan. NS Power seeks the Board's approval of this change in **Section 17** [sic] below.

[Exhibit N-3, p. 29]

[65] Also, on pages 21 and 98 of its application, NS Power sought Board approval of administrative changes to the introduction to Appendix Q (the Hedging Plan) of the Fuel Manual.

[66] In NSEB IR-27 and IR-28, NS Power confirmed that it is responsible to prudently manage its fuel portfolio in the best interests of its customers, and the Board does not normally approve the Fuel Manual (including Appendix Q) and its Hedging Plan. Instead, it said that the changes were filed for informational purposes and that the changes are intended to continue beyond the prior "rate stability period".

3.2.2.3 Findings

[67] NS Power is directed to make the change to s. 3.2.8 of the FAM POA discussed in NSEB IR-33. The Board approves NS Power's other proposed amendments to the FAM POA and to the FAM Tariff.

[68] As noted above, the Board does not provide approval of the Fuel Manual nor the Hedging Plan, and again confirms that it is NS Power's responsibility to ensure that it manages its fuel portfolio in a prudent manner, in the best interests of its customers.

3.3 Operating, Maintenance and General Costs

3.3.1 Overall Costs

[69] NS Power applied for an increase in its OM&G expenses in the test years. The OM&G expenses represent costs for operating and maintaining the utility's generation, transmission, and distribution facilities; delivering service to customers; and providing corporate support to these functions.

[70] Compared to the amount of \$297.4 million currently in rates for the restated 2024 compliance filing (2024CR), NS Power requests OM&G expenses of \$351.8 million in 2026 and \$357.9 million in 2027. This is an increase of \$54.4 million (18.3%) from the 2024CR to 2026 and a further \$6.1 million (1.7%) from 2026 to 2027.

[71] These operating costs are broken down by category in the following table for the 2024CR and the 2026 and 2027 test years:

Figure 9 – Operating costs by groups - 2024CR and 2026-2027 Forecast



[Exhibit N-33, p. 22]

[72] While not subject to review in this application because it is beyond the test period, NS Power forecasts OM&G costs to increase again from 2027 to 2028 by a further \$22.1 million (i.e., 6.2%).

[73] The proposed 2026 and 2027 amounts already reflect a reduction of \$9 million per year that NS Power agreed to deduct from OM&G costs in the settlement agreement. The utility agreed to reduce costs in the following amounts and categories:

- Energy Delivery - \$5 million;
- Customer experience and Innovation - \$2 million; and
- Corporate - \$2 million.

[74] NS Power engaged its consultant, ScottMadden Inc., to prepare a benchmarking report to review how the utility is performing compared to its peers. ScottMadden concluded that NS Power's "OM&G costs compare favorably to the peer group" and that the utility "is in the first quartile for most metrics despite low usage per customer compared to peers".

[75] The proposed increases to OM&G expenses are due to various reasons, but a major cause for the increased costs arises from staffing increases. NS Power was asked in a Board IR to show a break down of the forecast full-time equivalent employees (FTEs) in the 2026-2027 test years in each operating expense category compared to the 2024CR. While the company cautioned that it had restructured parts of its operations since the 2023-2024 GRA filing and it was unable to directly correlate the FTEs in 2024 to match the updated structure, it confirmed there is a forecast net increase of 507 FTEs from the 2024CR to 2026, a 24% increase:

	2024 Compliance	2026 GRA	2027 GRA	2026 GRA vs. 2024 Compliance	% Change	Explanation
Executive Management	4	4	4	-	0	
Legal and Corporate Secretary	12	11	11	(1)	-8	
Corporate Finance	33	33	33	-	0	
Communications and Public Affairs	10	15	15	5	50	Note 1
Human Resources and Safety	50	63	63	13	26	Note 2
Facilities, Procurement & Security	70	86	86	16	23	Note 3
Information Technology	204	239	244	35	17	Note 4
Regulatory Affairs	18	17	17	(1)	-6	
East Coast Energy Initiative	0	40	40	40	N/A	Note 5
Total Corporate Groups	401	508	513	107	27	
Head Office	20	20	20	-	0	
Thermal Plants	291	340	340	49	17	Note 6
Tufts Cove & Combustion Turbines	104	100	100	(4)	-4	
Solar, Hydro and Wind Energy	74	94	94	20	27	Note 7
Biomass	31	32	32	1	3	
Energy, Fuel and Risk Management	32	34	34	2	6	
Total Power Production	552	620	620	68	12	
Enterprise Asset Management & Project Implementation	118	116	116	(2)	-2	
Environment	24	30	30	6	25	Note 8
Customer Operations/Energy Delivery	769	950	918	181	24	Note 9
Customer Service/Customer Experience & Innovation	251	398	400	147	59	Note 10
NS Power Total	2115	2622	2597	507	24	

[Exhibit N-27, NSEB IR-42, p. 2]

[76] NS Power noted that its current number of FTEs is 2,478 (as of the date of the IR response, November 5, 2025). It noted that the figures in the above table do not reflect the \$9 million reduction in OM&G costs that the utility committed to remove in the settlement agreement. The utility also noted it had made a vacancy adjustment of \$5.7

million in 2026 to recognize that not all these positions would always be filled. Further, in response to questioning from Port Hawkesbury Paper (PHP) counsel, the company acknowledged that the increase of FTEs in the above table reflects a net variance after accounting for the estimated transfer of 22 NS Power employees to the Nova Scotia Independent Energy System Operator (IESO Nova Scotia) in December 2025 in Phase 1 of the transition and 32 employees in 2027 in Phase 2 (Transcript, January 12, 2026, pp. 1056-1058).

[77] Doane Grant Thornton LLP was engaged by Board Counsel to review, among other matters, NS Power's proposed OM&G costs. Doane Grant Thornton stated that it analyzed the company's financial information and investigated variances between the 2024CR amounts and the 2026 to 2027 forecasts. It also reviewed "the methodology and assumptions used in the OM&G forecast for reasonableness" and reviewed the benchmarking studies for NS Power against its peers. However, in questioning by the Board at the hearing, the Doane Grant Thornton panel confirmed that it did not conduct an organizational review to determine whether there was a different operational structure that would be more cost-effective and efficient.

[78] The Nova Scotia Department of Energy said in its closing submissions that the proposed increase in FTEs was not reasonable in light of affordability issues faced by NS Power's customers and that the proposed staffing increase was not justified:

102. From the evidence in this proceeding, the Department submits that NS Power has not clearly justified the need for the number of staff it forecasts for 2026. Although NS Power indicated that cuts would be difficult from the company's perspective, the Company intends to reduce labour costs in some undefined areas to comply with commitments made in the Consensus Agreement.

103. The Department's position is that NS Power has not sufficiently justified the Company's departure from industry standards and asks that the Board critically consider reductions to NS Power's staffing request to eliminate any unnecessary burden on ratepayers.

104. Considering NS Power's large growth in overall FTEs since the last rate application, the Department asks that the Board critically consider reductions to NS Power's staffing request to eliminate any unnecessary burden on ratepayers.

105. The Department submits that NS Power, like other organizations operating in the current economic environment, should be required to demonstrate cost management and operational efficiency. Section 34A of the *Act* allows the Board to order a "Savings Review" of NS Power and that the savings review be conducted by an independent party. Considering the concerns identified in this proceeding about NS Power's increased spending with no clear justification, the Department submits that the Board should order a Savings Review.

[Department of Energy Closing Submissions, January 30, 2026, p. 16]

[79] In its opening statement, the New Democratic Party Caucus asked the Board to examine the costs that the company is passing on to customers to ensure they are just and reasonable. It urged the Board "to do everything in its power to ensure Nova Scotians have affordable, reliable power and that Nova Scotia Power is held to the standard of ensuring they work in the interest of the public". In its closing submissions, the Liberal Caucus submitted that "an independent, comprehensive review of Nova Scotia Power's operations, governance, and long-term planning is warranted".

[80] NS Power noted that some of the proposed increases in OM&G costs are to address increased service requests by customers. For example, in the Regional Operations cost category, NS Power explained that population growth, an increasing number of customers, and load growth are reasons for a proposed \$4.8 million increase from the 2024CR:

Increased labour costs in Regional Operations in the 2026 forecast compared to the 2024 compliance are primarily due to additional resources required to complete customer requested work. The population growth in Nova Scotia has exceeded recent historical rates with 1-year average growth rates averaging 2.2 percent in 2021-2024 as compared to 0.5 percent in the preceding decade of 2011-2020. This population growth has contributed to increased customer-requested work, which has increased by over 40 percent over the 2021-2024 period. There were 27,000 wiring permits, 44,000 electrical inspections, 4,400 renovations, and 8,400 new customer connection requests in 2024 alone. Also, additional resources are required for execution of the \$1.3B Five-Year Reliability Plan and additional substations construction due to load growth.

...

These additional labour costs were determined through a review of all field work that Regional Operations performed from 2020-2024. The population growth and electrification have led to a 40% increase in customer-requested work, and the Five-Year Reliability Plan has resulted in a \$400M increase in transmission and distribution investment over the five-year period (\$900M compared to \$1.3B), which is an \$80M per year increase. [Emphasis added]

[Exhibit N-23, Doane Grant Thornton IR-34, pp. 1-2]

[81] In response to NSEB IR-12, NS Power stated that 65 community meetings were held across the province to discuss reliability and understand customer expectations. It said that no formal notes were taken during the sessions. At the hearing, it stated that these community meetings were conducted by NS Power's reliability team and supported by the communications group (Transcript, January 9, 2026, pp. 873-876).

[82] NS Power requested approval to increase its operational support for community and customer engagement. It has requested an increase in the Reliability Implementation group (Energy Delivery) of \$2.5 million from the 2024CR to 2026, with a further \$300,000 increase in 2027. Most of the increase (i.e., \$2.1 million) is for increased labour costs for the Reliability Implementation department which was formed after the 2023-2024 GRA. This centralized the utility's resources focused on improving system reliability. The largest cost is for additional staff on the Standards & Community Engagement team to engage with customers to improve customer consultation, centralized reliability planning, and execution of the 5-Year Reliability Plan. The company indicated that the reliability team is comprised of 59 employees, who support both the operational and capital parts of this initiative.

[83] There is also a requested increase in OM&G costs for "Communications and Public Affairs" of \$2.0 million from the 2024CR to 2026. This represents a 131% increase. NS Power explained that this is largely due to increased labour costs (\$900,000) to create a new Communication and External Engagement department for increased

engagement with interested parties and communities across the province to receive input and feedback, and to share more information on priorities, projects, and initiatives undertaken by the company in response to customer feedback. In response to NSEB IR-61, the company said that through “more engagements such as community meetings and open houses, NS Power can gather feedback that can be incorporated into plans for work in the community”. It said it can use these sessions to provide updates on hydro projects and reliability upgrades and its 5-Year Reliability Plan. There are also additional proposed costs related to communications and community engagement for consulting fees (\$700,000) and advertising expenses (\$300,000).

[84] Similarly, in “Grid Modernization and Customer Integration” there is a proposed increase of \$4.1 million from the 2024CR to 2026 (i.e., 68%) and a further \$400,000 increase in 2027. According to its response to NSEB IR-69, part of the increase is related to activities of the Smart Meter Operations Center for data analytics support to provide operational reporting on Smart Meter Operations, respond to customer inquiries on billing and usage, and support the design and evaluation of customer programs. However, there is also a proposed increase for customer engagement and communications:

The incremental labour for Customer Experience supports the maintenance of the expanding portfolio of digital solutions such as Green Button, My Energy Insights, the customer-facing website, and the large complex customer portal planned for 2026. In addition to the expanded digital channel support, the Customer Experience team is delivering a Customer First, role-specific training program to educate employees in delivering exceptional customer experience. The Customer Experience team is expanding its communication initiatives with customers via media campaigns and in-person engagements such as home shows to ensure customers have access to information and expertise in managing their energy needs.

[Exhibit N-27, NSEB IR-69, p. 2]

[85] In NSEB IR-12, NS Power was asked whether it had measured customer satisfaction about reliability to establish a baseline against which to test the 5-Year Reliability Plan. It was also asked about any quantitative measures it had identified as it planned to begin to implement the Reliability Plan, including any data it had collected about how the company's reliability initiatives would impact customer satisfaction:

While customer expectations provide valuable insights, NS Power does not anticipate using CSAT as a measure of the effectiveness of its Five-Year Reliability Plan. As detailed in the plan itself, NS Power is focused on the achievement of performance standards and has designed its investment tracks accordingly. NS Power anticipates that CSAT related to reliability concerns will be positively impacted by such investments by delivering decreased outage frequency and duration, but CSAT is not considered a consistent and repeatable reliability metric for benchmarking.

[Exhibit N-27, NSEB IR-12, p. 2]

[86] NS Power's witness panel reiterated this position at the hearing:

Q. So Nova Scotia Power is not intending to use a customer satisfaction metric in its reliability plan?

A. (MacIntosh) Yes, Mr. Mahody, if you consider the CSAT metric and then how the Five-Year Reliability Plan was created, the Five-Year Reliability Plan was created based on meeting the Nova Scotia Power Performance Standards. So CSAT is not a performance standard; ... Mr. Williams will add some additional context.

A. (Williams) Yes, Mr. Mahody, I think the CSAT outcomes are certainly -- it's valuable data. It's customers' perspectives, which I've expressed already is something we take very seriously and that we attempt to address. But as Mr. MacIntosh has described, we have -- in the regulatory context, we have the performance standards, which we would view as, in part, being responsive to or aligned with customers' expectations in relation to reliable service. And so we believe that the performance standards -- I mean, the performance standards allow for there to be an objective benchmark. The CSAT outcomes are, like I said, certainly valuable, but much more difficult to have an objective benchmark with those, as opposed to the performance standards. And so that's why the performance standards are being used as the point in which we're measuring our success in relation to reliability. [Emphasis added]

[Transcript, January 9, 2026, pp. 757-758]

[87] In support of the need for the Communications team to help other departments in their public engagement on reliability or other matters, NS Power stated:

A. (Williams) ... As I said, the groups we've discussed are all specialized groups, and so it's helpful when you go out to talk to the public to have -- just as when we appear before this Board -- to have the people that can respond to the questions that we anticipate receiving. So while we have a comms team that provides a communications and public affairs function and service to the company. They're not necessarily subject matter experts. And so while we could prepare those people to go out, it's more effective to provide the

people that know the material more intimately and can provide the detailed responses that often times are customers are asking. And I think that's important, just as it is in this room, to instill confidence in those who are asking the questions that the company has commanded the subject matter and has a definitive direction on it.

[Transcript, January 9, 2026, pp. 885-886]

[88] NS Power was also asked by the Board about its proposed increase of \$3.4 million from the 2024CR to 2026 for Corporate Human Resources, and an additional increase of \$200,000 in 2027. It said this is primarily due to increased labour costs for staffing level increases and salary escalation (\$2.3 million). In response to Doane Grant Thornton IR-14, the company said it needed a larger Human Resource team to support the increased number of employees. It stated that the Human Resource and Safety teams have grown by a total of 10 employees, with more Safety Specialists, additional employees to support Diversity, Equity and Inclusion programs and Labour Relations, and more "Human Resource Business Partners to support talent acquisition and new employees". NS Power said that there is also \$400,000 more for "talent management" which is handled by its parent Emera and allocated to the utility under the Affiliate Code of Conduct and Cost Allocation Manual (Doane Grant Thornton IR-16). There are also increased consulting costs of \$300,000 due to the increased staffing levels, mostly for medical consulting expense.

[89] On the issue of shared services with its parent Emera, at the hearing the NS Power panel acknowledged that it had not evaluated whether it was more economic to provide the human resource functions with internal staff or to outsource them to a third party and operate on a shared service model (Transcript, January 12, 2026, pp. 1000-1001). Further, the ScottMadden benchmarking study filed by NS Power indicated that the utility's total human resource costs per FTE (as of 2023) was 21% higher than the industry group median.

3.3.1.1 Findings

[90] NS Power's proposed increase in OM&G costs is significant. It represents a 20% increase in 2027 (18.3% in 2026) from the OM&G costs included in rates approved in the 2023-2024 GRA. The burden is on NS Power to show that the proposed OM&G costs are just and reasonable and needed to provide the required service to customers.

[91] The Board is satisfied that some of the increased OM&G costs are warranted. One such example is in "Energy Delivery" for Regional Operations (\$4.8 million) and Control Center (\$3.3 million). This includes increased costs to deliver connection and inspection services to customers and operating new grid-scale battery sites. The Board accepts NS Power's evidence that there has been a significant increase in customer requests for such services. NS Power noted that there has been a 40% increase in customer-requested work in its Regional Operations field work, including for such services as wiring permits, electrical inspections, renovations and new customer connections. Further, it said additional resources are required for execution of the \$1.3 billion 5-Year Reliability Plan and the construction of additional substations due to load growth. These services require more power line technicians, substation technicians, related apprentices, and supervisory staff.

[92] Further, NS Power's Regional Operations' costs must also increase to accommodate the three new grid-scale battery sites that are expected to be in service by 2026. This is required to allow the utility to meet renewable electricity standards (RES) requirements and to help integrate renewable generation on the grid and maintain reliability. Forecast costs to maintain these grid-scale batteries are \$970,583 in 2026 and \$1,247,406 in 2027 [Exhibit N-23, Doane Grant Thornton IR-35].

[93] There is also a 42% forecast increase in the Control Center category for labour expense in 2026 over 2024 actuals. However, NS Power explained that these additional resources are required immediately in the Control Center due to the significant increase in Independent Power Producer (IPP) interconnection requests and resulting from the FAM Audit Dispatch Study. NS Power noted that these additional employees are anticipated to transfer to the IESO Nova Scotia as part of the Phase 2 transition in 2027.

[94] In the circumstances, the Board finds the increased costs related to services like connection, inspection and interconnection requests are needed for the utility to provide the level of service expected by customers. Given the significant increase in customer requests for these specific services, the Board is satisfied that NS Power has responded appropriately by planning to add the required staff to meet the increased customer demand for these services so they can be provided within a reasonable time. As noted above, some increased operational costs also result from Board proceedings involving various customer representatives, including the FAM Audit Dispatch Study and the Interconnection processes matter.

[95] NS Power has also proposed increased OM&G costs related to addressing technology and cyber security matters. It proposed a total increase of \$10.2 million from the 2024CR to 2026 and a further \$1.8 million increase in 2027. These costs include a \$6.6 million increase for more consulting fees to support the cyber security program for both its Operational Technology (OT) and Information Technology (IT). The additional costs also include \$3.8 million for an incremental number of employees to support cyber security, the replacement of end-of-life legacy technology, and the introduction of new customer service. There is also \$3.2 million more for increased rental and maintenance

equipment and software as new vendor tools and capabilities are added to the utility's information technology. The Board accepts the utility's evidence that these costs are necessary to keep its IT systems updated and that they are reasonable. The reality is that this is an issue all companies must address. However, the Board recognizes that there are currently proceedings underway about NS Power's cyber incident in the Spring of 2025 (Matters M12273 and M12600). While the Board approves the operational costs proposed in this GRA related to updating and operating the utility's technology, this approval does not foreclose a finding of imprudence in those cyber incident matters, if that is warranted, following the Board's review of NS Power's cyber preparedness and response.

[96] The Board has concerns about the transition of system operator staffing from NS Power to IESO Nova Scotia, including the potential for overlap and duplication. IESO Nova Scotia has forecast some transition costs for NS Power employees in its recent 2025-2026 (M12412) and 2026-2027 (M12663) revenue requirement applications. The Board will closely monitor this issue to ensure that ratepayers are not impacted by unnecessary costs incurred by these respective entities.

[97] However, the Board finds that NS Power has not demonstrated the need for its proposed increase in customer engagement and communications staff. First, the Board notes that NS Power appears to have been able to conduct its customer and community engagement with its present staffing complement, having conducted 65 community meetings recently across the province. The Board finds that adding more staff on these initiatives would be redundant.

[98] Secondly, and more importantly, despite the assertion that more staff is needed for customer engagement about issues like reliability, NS Power's witnesses confirmed that the company has not conducted formal surveying to measure customer satisfaction about reliability to establish a baseline against which to test its 5-Year Reliability Plan. The company confirmed it did not take any formal notes at its 65 community meetings to record the customers' expectations about reliability, although it did follow up on general action items with customers. However, company officials confirmed it will not measure customer satisfaction to determine the effectiveness of its Reliability Plan. Rather, NS Power is planning to rely on the achievement of performance standards and has designed its investments accordingly. It said measuring customer expectations "is not considered a consistent and repeatable reliability metric for benchmarking".

[99] Against this backdrop, the Board does not consider it reasonable to approve the company's request for additional staffing to conduct customer engagement, particularly about reliability issues, when it has no intention to measure customer satisfaction on the topic. Instead, it intends to base its conclusions about the success of the Reliability Plan on its performance metrics. Further, NS Power was unable to adequately explain how more costs were needed to support existing digital programs such as the My Energy Insights platform under the Grid Modernization and Customer Integration group. The utility also acknowledged in its testimony that it did not conduct any cost-benefit analysis about its customer engagement and communication initiatives or provide a plan outlining the measures or targets it hoped to achieve.

[100] To be clear, the Board considers it reasonable for the company to measure the success of its actions on issues like reliability by satisfactorily meeting its performance standards. That is likely one of the best methods to measure its success on such initiatives. However, the Board recognizes that customer engagement is beneficial. Nevertheless, an appropriate balance must be struck. Given the affordability concerns expressed in many letters of comment filed in this matter, the Board concludes that ratepayers consider the balance lies in not increasing engagement and communications costs at this time. Based on these letters of comment, customers do indeed care about reliability, but the Board concurs with the utility that achieving the performance metrics provides an objective measure of success on that initiative. Like many are forced to do in their daily lives, members of the public want NS Power to do everything possible to keep costs down where possible.

[101] The Board also finds that NS Power has not demonstrated that the addition of human resource staffing, and related costs, are warranted. The Board notes that the ScottMadden benchmarking study indicated that NS Power's OM&G costs per FTE were 21% higher than the industry group median (as of 2023). In questioning by the Board, the utility was unable to adequately explain why additional employees were required to support its Diversity, Equity and Inclusion programs. Further, in response to questions from the Board, NS Power acknowledged that it has not evaluated whether it is more economic to provide these services internally versus a third party or the shared services model it now has with its parent Emera. In the circumstances, the Board finds that the requested \$3.4 million increase in 2026 (and \$200,000 more in 2027) is not warranted.

[102] Based on the foregoing, the Board denies NS Power's proposed OM&G costs related to customer engagement, communications and human resource functions in the following amounts in the associated categories, with the reductions to be applied in each test year:

- Reliability Implementation (Energy Delivery) - \$2,000,000;
- Communications and Public Affairs (Corporate Groups) - \$2,000,000;
- Grid Modernization and Customer Integration (Customer Experience and Innovation) - \$2,000,000; and
- Corporate Human Resources (Corporate Groups) - \$2,000,000.

[103] The Board directs that the above \$8,000,000 per test year reduction is to be reflected in a compliance filing. Further, the Board directs that these reductions are to be applied in addition to the OM&G reductions agreed to by NS Power in the settlement agreement. The Board notes that its directed reduction of OM&G costs in this decision does not deny NS Power's recovery of costs it has incurred. Rather, the effect of the Board's finding is to set the OM&G cost envelope that the utility is expected to operate within. The OM&G cost amount approved in this decision is what the Board has determined are reasonable costs for NS Power in 2026 and 2027.

[104] The Department of Energy submitted that the Board should order an independent savings review for NS Power under s. 34A of the *Public Utilities Act*, which would be conducted by a third party. The New Democratic Party and Liberal Party caucuses asked the Board to ensure that the costs requested by the utility are reasonable. They all highlighted affordability, as did most of the letters of comment received by the

Board. While the Board seriously considered the Department of Energy's request, it has decided, for reasons that follow, that such a review should not occur at this time.

[105] First, this general rate application has served as a thorough review of NS Power's operations. In terms of the Board's process, several expert consultants were engaged by Board Counsel to review different aspects of the application. This included Doane Grant Thornton, which conducted a thorough review of the OM&G costs, including a review of the methodology and assumptions used in the forecast of these costs. The Board also had the benefit of reviewing the benchmarking study prepared by NS Power's consultant, ScottMadden, which confirmed that the utility's OM&G costs compare favourably to its peer group and it "is in the first quartile for most metrics despite low usage per customer compared to peers". In one instance where the benchmark did not meet its peers (i.e., the human resource function), the Board has ordered a reduction in costs. Second, the application was preceded by lengthy negotiations between the utility and most of its customer groups, which resulted in a settlement agreement. Finally, the Board observes that different parts of NS Power's operations are reviewed on a regular basis, including the FAM audit every two years and the utility's annual performance standards report. In addition, there is a 5-year review of the performance metrics currently underway. There is also a separate review underway of NS Power's \$1.3 billion 5-Year Reliability Plan. Also, since the last general rate application, the Board initiated a comprehensive inquiry under s. 30(5) of the *Public Utilities Act* into the extent, condition and value of the utility's property and assets. An independent study was conducted by Board Counsel consultant EA Technologies, who reviewed among other matters, the

utility's asset management practices. Accordingly, while the Board does not rule out a future savings review, it has decided not to order one at this time.

[106] Another issue raised at the hearing was the issue of executive compensation. While this is a matter relating to OM&G costs, it is dealt with separately in the next section of this decision.

[107] NS Power has forecast OM&G costs of \$8.9 million at Trenton Unit 5 and Lingan Unit 2 during the test period due to a change in the retirement assumptions for these coal units and increased hours of operation. Given a number of issues related to these coal units, this item is also canvassed separately in this decision.

3.3.2 Executive Compensation

[108] The *Public Utilities Act* prohibits NS Power from recovering bonuses and incentives paid to an executive employee. Other remuneration may only be recovered as prescribed by regulation:

64B (8) Nova Scotia Power Incorporated shall not recover from any rate, charge or fee approved by the Energy Board

(a) any bonus or incentive compensation; or

(b) any other remuneration, except remuneration that is prescribed by the regulations,

paid to an executive employee of Nova Scotia Power Incorporated as identified in an approved report or determined by the Energy Board.

[109] The *Nova Scotia Power Incorporated Regulations*, NS Reg 231/2012, enacted on December 21, 2012, allow for the recovery of remuneration paid to executives as follows:

Salary and compensation recoverable from rates, charges or fees

3 For the purpose of subsection 64B(8) of the Act, Nova Scotia Power Incorporated may recover the following remuneration from its rates, charges or fees approved by the Board:

- (a) for the Chief Executive Officer, no more than a salary equaling a 110% compa-ratio as provided for in the pay plan and no more than an additional 13% of the amount of that salary representing other benefits and compensation;
- (b) for each executive other than the Chief Executive Officer, no more than a salary equaling a 100% compa-ratio as provided for in the pay plan and no more than an additional 13% of the amount of that salary representing other benefits and compensation.

[110] The “pay plan” referenced in s. 3 of the regulations is the “Senior Officials Pay Plan approved by the Governor in Council by Order in Council 2007-85...as amended from time to time”.

[111] By Order in Council 2023-138, dated May 9, 2023, the Governor in Council revoked the Senior Officials Pay Plan approved by Order in Council 2007-85 and approved a new Senior Officials Pay Plan. The new Senior Officials Pay Plan is materially different than the former plan.

[112] The former plan included two pay scales; one specifically designated for Associate Deputy Ministers and the other specifically designated for Deputy Ministers. Both scales on the former pay plan ranged from compa-ratios of 80% to 110%.

[113] The new Senior Officials Pay Plan includes five pay scales, all of which range from compa-ratios of 80% to 100%. None of these pay scales are specifically designated as applying to Associate Deputy Ministers, Deputy Ministers or a new class of Executive Deputy Ministers that was created around the same time that the pay plan was changed.

[114] In applying the *Nova Scotia Power Incorporated Regulations* to the new pay plan to determine the amount of executive remuneration it could recover through the rates that it charges to its customers, NS Power decided that the amount payable to executives other than the chief executive officer under s. 3(b) was the maximum amount payable

under the pay plan. NS Power calculated the amount recoverable for remuneration to its Chief Executive Officer as 10% more than the maximum amount payable under the new pay plan.

3.3.2.1 Findings

[115] Although the *Nova Scotia Power Incorporated Regulations* have not been amended and continue to refer to a repealed Order in Council, the *Interpretation Act* says the regulations continue to apply with reference to the replacement provisions relating to the same subject matter or to the repealed enactment as far as is necessary to give them effect:

Repeal and substitution by amendment or revision

24 (1) Where an enactment is repealed and other provisions are substituted by way of amendment, revision or consolidation,

(b) a reference, in an unrepealed enactment to the repealed enactment, shall, as regards a subsequent transaction, matter or thing, be read as a reference to the provisions of the substituted enactment relating to the same subject-matter as the repealed enactment, but where there are no provisions in the substituted enactment relating to the same subject-matter, the repealed enactment shall be read as unrepealed as far as is necessary to maintain or give effect to the unrepealed enactment.

[116] The difficulty in this case is that, although the replaced provisions relate to the same subject matter, the pay plan is different enough that the regulations cannot be directly applied. At the same time, the pay scales in the former pay plan were also subject to periodic updates and, since the pay plan has been repealed, there have been no updates to the old pay scales. The guiding language in the *Interpretation Act* seeks to maintain or give effect to the unrepealed enactment.

[117] Under the former pay plan, NS Power was entitled to recover remuneration paid to its Chief Executive Officer at the maximum pay available to Deputy Ministers. As mentioned, NS Power's application of the new pay plan would allow the recovery of an

amount exceeding the maximum pay available to Deputy Ministers. As such, it is inconsistent with the previous intent. The maximum salary set out in the new pay plan is 100% of the SO5 scale. The Board finds that NS Power may recover this amount for remuneration paid to its Chief Executive Officer.

[118] Pending any amendments to the *Nova Scotia Power Incorporated Regulations*, the Board considers it appropriate to maintain the 10% differential between the remuneration allowed to be recovered for the Chief Executive Officer and other executive officers. The Board finds that NS Power may recover an amount equal to 90% of the SO5 scale for its other executive employees. NS Power is directed to make these changes in a compliance filing.

3.4 Depreciation

[119] 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. Assets with an expected service life greater than one year are typically capitalized and depreciated over their expected lives.

[120] 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.

[121] As it relates to regulation of depreciation, s. 38 of the *PUA* states:

Annual depreciation

38 (1) Every public utility shall make provision for proper and adequate annual depreciation of its property and assets used and useful in furnishing, rendering or supplying each type or kind of service, and shall in respect thereof keep necessary and proper accounts.

(2) Such annual depreciation shall be calculated by the straight line method or by such other method as the Board may from time to time prescribe.

(3) Every public utility shall report to the Board the annual rates of depreciation from time to time applied to the several classes of property in such public utility.

(4) The Board may ascertain and determine what are proper and adequate annual rates of depreciation of the several classes of property in any public utility, and such public utility shall thereupon and thereafter conform its depreciation account to the rates so ascertained and determined.

(5) The Board may revise such rates of depreciation from time to time as it deems necessary or expedient.

Further, Sections 40 and 41 of the *PUA* state:

Regulations respecting depreciation

40 The Board may also prescribe rules, regulations and forms of accounts regarding depreciation which a public utility is required to observe, carry into effect and follow.

Rates of utility to include allowance for depreciation

41 In fixing rates, tolls and charges to be paid to a public utility for any service, the Board shall include proper allowances for depreciation.

[122] NS Power 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, NS Power tracks its assets in pools at the mass property or location level. This methodology is standard in the electric utility industry, as tracking a significant number of assets on an individual asset basis is not practical and is cost prohibitive. NS Power's asset pools are depreciated over a period that approximates their estimated remaining useful lifespan. A fraction of each asset pool's original cost is treated as a depreciation expense each year until the asset investment and expected removal costs are fully recovered. Per the *PUA*, NS Power 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.

[123] Depreciation expense for NS Power 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, 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, such recovery also occurring over the expected useful life of the assets.

[124] In its 2023-2024 general rate application, NS Power noted that a depreciation study would typically precede or coincide with a GRA process. However, prior to the 2023-2024 GRA, NS Power did not complete a depreciation study. NS Power stated the reason for this was the uncertainty surrounding the timing of retirement of the

coal plants having such a material impact on depreciation rates. As such, the company's depreciation rates had not been updated by way of a depreciation study since 2011 when intervenors and NS Power entered into a black box settlement agreement which was approved by the Board at that time. The black box agreement set depreciation rates to achieve an overall desired result of mitigating rate pressures without specifying the exact underlying means used to calculate the rates.

[125] As a result, in its *2023-2024 GRA* Decision, the Board directed NS Power to complete a depreciation study prior to filing its next GRA. NS Power complied with this directive by filing a new depreciation study as Appendix 8A [Exhibit N-7] in the current GRA. The depreciation study was completed by NS Power's consultant, Gannett Fleming.

[126] For most of NS Power's Plant accounts, the Gannett Fleming depreciation study, and the related proposed NS Power 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.

[127] To meet federal and provincial decarbonization legislation, NS Power expects it will have to retire some of its existing coal-fired generating assets and associated marine unloading and fuel delivery facilities by 2030. However, NS Power has not yet fully recovered its investment in these assets, nor has it fully recovered the costs it will incur to decommission these facilities. While NS Power could seek Board approval to accelerate the recovery of depreciation expenses and decommissioning costs to match the remaining useful lives of the assets, doing so would cause a substantial increase in

rates. Therefore, to recover these energy transition costs in a more affordable manner, as part of its 2023-2024 GRA, NS Power proposed to transfer them to a regulatory asset, which is called a Decarbonization Deferral Account (DDA). To the extent that costs transferred to the DDA are not offset by governments (to recognize the various policy choices reflected in the laws leading to the premature retirement of assets and the broader social benefits from a decarbonized electricity system), they would be recovered from customers over an undetermined future period.

[128] In a settlement reached between NS Power and representatives of all its major customer classes, the parties agreed in principle to a DDA that was narrower in scope than originally proposed by NS Power in its 2023-2024 GRA. As part of this agreement, NS Power was to develop policies and procedures for this DDA through a consultative process after the general rate application. The Board agreed with this approach in its *2023-2024 GRA Decision* and approved the DDA in principle.

[129] In Matter M11220, NS Power filed a DDA Manual, which set out the policies and procedures it proposed to follow to account for the unrecovered net book value (NBV) of assets and unrecovered decommissioning costs transferred to the DDA for future recovery. In that matter, NS Power sought formal Board approval of the DDA, as outlined in its DDA Manual. In its decision for the matter (2024 NSUARB 67), the Board approved the DDA with modifications. As part of the current GRA proceeding, NS Power said it intends to securitize the net book value of the assets within the scope of the DDA. This issue is addressed in a subsequent section of this decision.

[130] In the DDA matter (M11220), the Board did not direct NS Power to accelerate depreciation of coal generation assets currently in-service or to accelerate

amortization of any of the retired assets that will be transferred to the DDA. Instead, the Board directed NS Power to continue using existing depreciation rates for these assets until its next GRA proceeding when a new depreciation study would be filed. In effect, the Board's decision approved the future transfer of costs to the DDA, but the amortization of those costs remained to be determined. Therefore, in the interim there would have been no change to the revenue required from customers upon transferring costs to the DDA.

[131] Further, in Matter M11220, NS Power noted if its next depreciation study were to include the company's thermal assets, it would effectively require the acceleration of depreciation of those assets in a manner sufficient to recover the unrecovered costs over the expected remaining useful lives. NS Power believed that the accelerated depreciation expense required to recover these costs over this period would introduce significant rate increases for customers in the near term. The company also noted that it was continuing to seek funding from the federal government for some of its decarbonization costs. As such, increasing the depreciation expense to recover the costs over the expected remaining useful lives of the assets would not allow for consideration of any federal funding that may be received. NS Power, therefore, proposed that the thermal assets to be transferred to the DDA be excluded from the company's next depreciation study. All other assets not included in the scope of the DDA would be considered within the company's upcoming depreciation study.

[132] The Board agreed with NS Power's proposed depreciation study approach in Matter M11220 (DDA Manual). However, given the relatively small undepreciated balances of the Trenton 5, International Coal Pier, and Steam General Plant assets, the Board noted potential merit in accelerating depreciation of these assets so that they are

fully depreciated upon retirement. Therefore, while not directing accelerated depreciation of those particular assets at that time, the Board directed NS Power to include these assets in its next depreciation study.

[133] In the current GRA, NS Power has included all assets within its updated depreciation study for information purposes. However, consistent with the Board's finding in Matter M11220, NS Power did not update the depreciation rates associated with the assets within the scope of the DDA. The assets include Point Aconi, Trenton (including units 5 and 6 and common Plant), the Point Tupper Marine Terminal, Sydney International Coal Pier, and Steam General Assets. These assets are all intended to be retired before 2030 and, as such, are within the scope of the DDA. As noted previously, and as addressed in a later section of this decision, NS Power intends to securitize these assets. NS Power's remaining thermal assets, including Lingan, Point Tupper, Tufts Cove and Port Hawkesbury Biomass, are currently envisioned to provide service beyond 2030. They have, therefore, been included in NS Power's updated depreciation study complete with updated depreciation rates.

[134] The proposed depreciation rates in the updated depreciation study would result in NS Power having an annual depreciation expense of \$385.2 million when applied to depreciable Plant balances as of December 31, 2023. The depreciation rates developed from NS Power's updated depreciation study, with consideration of the settlement agreement, are provided per asset account in Appendix "A" of the settlement agreement. The depreciation rates resulting from consideration of the settlement agreement produce an annual NS Power depreciation expense of \$365.7 million when applied to depreciable Plant balances as of December 31, 2023. A summary table of

depreciation rates and expense resulting from the settlement agreement is presented in Figure 8-1 of the GRA, and reproduced as follows:

Function	GBV- Studied Plant (December 31, 2023) (\$)	Accrual Rate	Total Accrual Amount (\$)
Steam Production	2,616,967,386	6.47	169,219,037
Hydro Production	614,021,913	2.08	12,801,477
Solar	1,582,854	3.89	61,606
Other Production	492,589,726	4.50	22,182,232
Transmission	1,254,616,801	2.70	33,825,592
Distribution	2,137,686,386	3.45	73,717,352
General	740,996,013	7.27	53,887,702
Total	7,858,461,079	4.65	365,694,997

[Exhibit N-3, pp. 40-41]

[135] The figures in the table above include annual accruals calculated for all thermal assets, including those within the scope of the DDA. However, NS Power is not proposing to increase the depreciation rates for the assets included within the scope of the DDA, as the company intends to securitize those assets. This is summarized in the following table:

Function	GBV- Studied Plant (December 31, 2023) (\$)	Accrual Rate	Total Accrual Amount (\$)
Steam Production	2,616,967,386	2.62	68,461,258
Hydro Production	614,021,913	2.08	12,801,477
Solar	1,582,854	3.89	61,606
Other Production	492,589,726	4.50	22,182,232
Transmission	1,254,616,801	2.70	33,825,592
Distribution	2,137,686,386	3.45	73,717,352
General	740,996,013	7.27	53,887,702
Total	7,858,461,079	3.37	264,937,219

[Exhibit N-3, p. 41]

[136] Applying the proposed depreciation rates in the preceding Table to forecast monthly balances of depreciable Plant throughout the test period results in a forecast depreciation and accretion expense of \$282.4 million in 2026 and \$300.8 million in 2027.

If securitization of the assets included within the scope of the DDA had not been assumed by NS Power in its application, the depreciation and accretion expense to be paid by ratepayers would have increased annually by \$26.6 million, resulting in totals of \$309.0 million in 2026 and \$327.4 million in 2027.

[137] In 2026, the depreciation and accretion expense is forecast to increase by \$2.5 million over the 2024 GRA Compliance Filing. In 2027, the depreciation and accretion expense is forecast to increase by \$18.4 million from the 2026 forecast amount. These increases result from updated depreciation rates and capital additions to Plant in service, as filed in the approved Annual Capital Expenditure Plans (ACE) and other capital expenditures approved by the Board. NS Power's average NBV was \$4.456 million in the 2024 GRA Compliance forecast. In the updated test period forecast, the NBV has increased to \$4.895 million in 2026 and \$5.186 million in 2027.

[138] Dustin Madsen of Emrydia Consulting Corporation was engaged by Board Counsel to provide expert analysis, recommendations and testimony about NS Power's depreciation practices, including reviewing and assessing Gannett Fleming's depreciation study and proposed depreciation rates.

3.4.1 Settlement Agreement Reduction in Depreciation and Accretion Expense

[139] As noted above, the depreciation rates from the settlement agreement, result in annual NS Power depreciation expense being approximately \$19.5 million lower than that calculated by the Gannett Fleming study, when applied to depreciable Plant balances as of December 31, 2023. This reduction results from changes to a) some of the estimated net salvage costs and rates in the Gannett Fleming study and b) some of the estimated asset service lives in the Gannett Fleming study. The Board must determine

whether these changes and the related reduction in depreciation and accretion expense are appropriate.

3.4.1.1 Net Salvage Costs

[140] Depreciation expense for NS Power includes both a depreciation and net salvage component. Net salvage recovers the expected future costs to salvage and remove/decommission assets, including any salvage proceeds. Gannett Fleming's depreciation study uses the Traditional Method for recovery of net salvage costs. This method of recovering net salvage costs embeds the recovery of net salvage costs over the life of the assets based on the approved depreciation parameters. The net salvage parameter in this case is expressed as either a positive or negative percentage based on the original cost of the asset.

[141] In his evidence, Mr. Madsen stated that the Traditional Method is the most technically correct and reasonable method of recovering net salvage costs from customers. He noted that linking the recovery of the cost to the depreciation of the assets ensures that the costs to salvage those assets are recovered over the lives of the same assets. Thus, it similarly ensures that the customers who benefit from the currently installed assets pay to remove those assets.

3.4.1.1.1 Production Plant

[142] As it relates to its generation assets, NS Power's depreciation study requires it to estimate the future cost of decommissioning its generation sites, as depreciation rates are generally set to recover the unrecovered decommissioning costs over the estimated remaining useful lives of the assets. In its current depreciation study, NS Power's net salvage estimates for production Plant reflect estimated

decommissioning costs associated with each generating station, including its hydro systems, based on site-specific decommissioning studies for each location.

[143] For Steam and Other Production Plant, the decommissioning studies were conducted by Stantec, Inc., an international engineering consulting firm. For Hydro Production Plant, the decommissioning studies were conducted by Hatch Ltd., a global, multidisciplinary management and consulting engineering company; Boreas Heritage Consulting Inc. reviewed archaeological costs; and J.B. Yates Engineering Limited reviewed partial decommissioning costs. The Hatch and Boreas studies were filed in this Matter in Exhibit N-7, while the Yates report was filed as Undertaking U-10.

[144] Generally, the collection of net salvage values in rates is based on current dollars at the time of the depreciation study and then inflated forward to the future years in which the costs are forecast to occur. However, per the GRA settlement agreement, decommissioning cost estimates for all production Plant have been calculated in 2024 dollars only (i.e., inflation to the forecast years of decommissioning has been removed). The settlement agreement also removes contingency costs from all production Plant decommissioning cost estimates. These settlement agreement changes result in NS Power's proposed production Plant depreciation rates being lower than those calculated in the Gannett Fleming depreciation study.

[145] For NS Power's Hydro Plant, the hydro decommissioning studies provided decommissioning cost estimates for full and partial decommissioning. A summary of these costs was presented in Exhibit N-7, Appendix 8E. Gannett Fleming's depreciation study and NS Power's proposed depreciation rates have been set using hydro decommissioning estimates based on the partial decommissioning scenario. Estimated

costs for partial decommissioning include removal and site remediation of buildings and structures, turbines, generators and auxiliaries, electrical services, and common services. The partial decommissioning estimated costs exclude costs for removal of structures required for water management, such as dams, spillways and gates.

[146] NS Power estimated the future cost to partially decommission the Wreck Cove, Mersey and Tusket hydro systems as \$27 million, \$228 million and \$293 million, respectively, for a total of \$548 million. However, given the magnitude of these costs and the broad policy, societal, and environmental considerations and factors that would need to be considered to decommission such sites, NS Power believes that removing these costs from customer rates, at this time, is a reasonable approach to balancing cost recovery and rate pressure for customers. As such, Gannett Fleming's depreciation study and NS Power's proposed depreciation rates further exclude any decommissioning costs for the Wreck Cove, Mersey and Tusket hydro systems. NS Power is only proposing to do so to the extent that it does not prejudice its ability to recover such costs in the future should they be prudently incurred.

[147] Finally, as per the GRA settlement agreement, archaeological reconnaissance costs have been removed from NS Power's hydro Plant partial decommissioning cost estimates. This settlement agreement change results in NS Power's proposed hydro Plant depreciation rates being further lowered from those calculated in the Gannett Fleming depreciation study.

3.4.1.1.2 Transmission, Distribution and General Plant

[148] Gannett Fleming's net salvage estimates for transmission, distribution and general Plant accounts were based in part on historical data compiled for the years 1993 through 2023. The net salvage estimates by account are expressed as a percent of the

original cost of Plant retired. Further, the historical net salvage data for the years 1976 through 1992 were available only in total for each of the transmission, distribution and general Plant functions. Therefore, though not considered as the statistical basis for the net salvage estimates, the data provided Gannett Fleming with some probative value.

[149] Specifically for NS Power's transmission and distribution Plant, the net salvage estimates were developed based primarily on Gannett Fleming's judgement, which considered a number of factors. The primary factors included an analysis of historical data; the net salvage characteristics of other electric utility properties; a knowledge of management's plans and operating policies; and net salvage estimates from previous studies of NS Power and other electric companies.

[150] The GRA settlement agreement made the following changes to Gannett Fleming's recommended net salvage rates:

- Reduced the Net Salvage Rate for Account 354.00 - Transmission Towers and Fixtures from 40% to 20%,
- Reducing the Net Salvage Rate for Account 355.00 - Transmission Poles and Fixtures from 60% to 20%, and
- Reducing the Net Salvage Rate for Account 365.00 - Distribution Overhead Conductors and Devices from 30% to 26%.

These settlement agreement changes result in NS Power's proposed depreciation rates for the related accounts being lower from those calculated in the Gannett Fleming depreciation study.

3.4.1.2 Estimated Average Asset Service Lives

[151] Key elements influencing the determination of depreciation expense are average asset service lives and survivor curves. Survivor curves (also referred to as lowa 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 the assets that are expected to continue to be in service. The selection of a specific survivor curve is informed by a depreciation expert's judgement regarding the visual and mathematical fit to a set of data points, peer data and discussions with utility company management and operations staff.

[152] In Gannett Fleming's depreciation study, the average asset service lives were estimated based on compiling historical data for the Plant accounts, analyzing this data through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group based on interpretations of the historical data analyses and the probable future.

[153] Gannett Fleming's service life estimates were based on informed judgement which considered a number of factors. The primary factors included statistical analyses of data; current company policies and outlook as determined during field reviews of the property and other conversations with management; and the survivor curve estimates from previous studies and other electric companies.

[154] The GRA settlement agreement made the following changes to Gannett Fleming's estimated average asset service lives:

- Increasing the estimated service life of Account 353 – Transmission Station Equipment from Survivor Curve 45-R2.5 to Survivor Curve 48-R2.5, which represents a service life increase of three years, and
- Increasing the estimated service life of Account 390.10 – General Plant Structures and Improvements from Survivor Curve 42-R2.5 to Survivor Curve 43-R3, which represents a service life increase of one year.

[155] These settlement agreement changes result in NS Power's proposed depreciation rates for the related accounts being lower than those calculated in the Gannett Fleming depreciation study.

[156] In his evidence, Mr. Madsen took issue with the recommended survivor curve for Account 353. As an alternative, he recommended a 50-R2.5 survivor curve for this account. This is discussed in more detail in section 3.4.3 of this decision. Mr. Madsen also recommended no change from the 42-R2.5 survivor curve for Account 390.10.

3.4.1.3 Findings

3.4.1.3.1 Exclusion of Wreck Cove, Mersey and Tusket Hydro System Decommissioning Costs from Proposed Depreciation Rates

[157] NS Power believes that removing the Wreck Cove, Mersey and Tusket hydro system decommissioning costs from customer rates, at this time, is a reasonable approach to balancing cost recovery and rate pressure for customers. The utility further emphasized that decommissioning these systems would entail extraordinary environmental, cultural, commercial, and social impacts, including large-scale habitat disruption, exposure of extensive shorelines, risks to hundreds of archaeological sites, loss of waterfront property and associated economic value, and potential impacts on potable water supplies. In addition, Wreck Cove plays a critical role in system reliability,

providing peak capacity, operating reserves, black start capability, and support for integrating renewable generation, making decommissioning particularly unlikely in the foreseeable future.

[158] Mr. Madsen identified a concern related to NS Power's proposed exclusion of these hydro system decommissioning costs from proposed depreciation rates. Specifically, he stated that under the proposal, future customers may be required to either pay a disproportionate amount of the costs to salvage the assets while they are still in use, or customers that no longer benefit from those assets will be required to pay for those assets. In effect, the proposal presents an intergenerational equity concern.

[159] This notwithstanding, Mr. Madsen supported NS Power's proposal to exclude these decommissioning costs from the proposed depreciation rates. In coming to this determination, he stated:

... it is important to remember that the collection of net salvage in rates is based on a forward-looking estimate of the cost to salvage the installed assets. That estimate is often based on historical costs to salvage assets, inflated forward to the future years the costs will be incurred. The issue in this case as noted by NS Power in its Application, is that there is significant uncertainty whether the costs will actually be incurred. Indeed, having reviewed the detailed salvage studies and the policy, societal, and environmental reasons for why full salvage of the installed assets would not be in the public interest, I agree that the likelihood that the assets will be fully salvaged is low. [Emphasis added]

[Exhibit N-34, pp. 111-112]

[160] In its response to NSEB IR-85, NS Power stated that it shared the intergenerational equity concern related to removing Wreck Cove, Mersey and Tusket hydro system decommissioning costs from proposed depreciation rates. However, until there is greater certainty about whether these costs will occur, the company believes the proposed approach to remove them from revenue requirement is a measured and responsible approach that helps to ensure rates are just and reasonable.

[161] Per NS Power's *2025 10-Year System Outlook Report* (Matter M12386), the Board notes that Wreck Cove is NS Power's largest hydro system. It has the ability to quickly provide 212 MW of peak capacity from two operating units and average annual generation of 300 GWh (soon to increase to 315 GWh). This represents approximately 8% of NS Power's forecast 2035 system peak, and roughly 3% of NS Power's forecast 2035 net system requirements. As NS Power noted, Wreck Cove also plays a critical role in providing required operating reserves, black start capability, and support for integrating renewable generation. In this context, the Board agrees with NS Power and Mr. Madsen that Wreck Cove is likely to be maintained indefinitely. Therefore, for the purposes of the current GRA, the Board finds that it is appropriate to exclude Wreck Cove decommissioning costs from the proposed depreciation rates.

[162] The Mersey Hydro System has a capacity of 42.5 MW, and an annual contribution of approximately 220 GWh toward NS Power's renewable energy targets. As noted in NS Power's 2026 ACE Plan, NS Power's 2020 Integrated Resource Plan (IRP) analysis compared the cost of rebuilding Mersey versus decommissioning it and replacing its energy and capacity contributions with alternative resources. Across all scenarios, redeveloping Mersey was more economic than decommissioning. The 2023 Evergreen IRP process reaffirmed these findings. The 2025/2026 IRP will provide an updated framework for evaluating the Mersey system, incorporating refreshed assumptions on load growth, emissions targets, resource costs and system integration. No final decisions on decommissioning or redevelopment of the Mersey system will be made until direction is received from the 2025/2026 IRP. With this in mind, the Board finds that it is appropriate to exclude Mersey decommissioning costs from the proposed depreciation rates for the

purposes of the current GRA. This can be reconsidered for NS Power's next depreciation study, should the 2025/26 IRP determine that decommissioning of Mersey is the preferred option.

[163] The Tusket system has a total capacity of 2.7 MW, and annual generation of approximately 12,000 MWh. This system is small compared to Mersey, and very small compared to Wreck Cove. As such, it may be questionable whether future refurbishment of this system is favourable compared to decommissioning and replacement with other less expensive renewable generation. However, the Board is aware that in the near term, NS Power intends to file an updated capital approval application for the Tusket Main Dam refurbishment. At that time, the decision to proceed with refurbishment or decommissioning will be tested by the Board. In the interim, for the purposes of the current GRA, the Board finds that it is appropriate to exclude Tusket decommissioning costs from the proposed depreciation rates.

[164] As noted previously, NS Power is only proposing to exclude decommissioning costs for the Wreck Cove, Mersey and Tusket hydro systems from customer rates to the extent that it does not prejudice its ability to recover such costs in the future should they be prudently incurred. The Board approves the exclusion of these costs for the 2026 and 2027 test years; however, its decision is limited to those years. How NS Power proceeds after the test years may be subject to further review.

[165] The above notwithstanding, the Board takes note of Mr. Madsen's evidence where he states NS Power's change in approach to recovering net salvage costs for these assets warrants that the company undertake an effort to fully reconcile all net salvage and actual salvage costs that have been recovered and paid for by customers. He

indicated that this information is important as NS Power will continue to seek to recover certain salvage costs for these assets and it is critical for parties to understand how much has been collected to date for the final (or terminal) salvage of the assets. He therefore recommended that NS Power provide a reconciliation showing the annual collection of interim and final net salvage in rates since the date the assets were installed. He also recommended that this same information be presented for actual interim salvage costs that have been incurred each year for each of the hydro assets where NS Power has proposed to cease collection of the final net salvage costs for the assets.

[166] During the hearing, NS Power was asked if it could provide this information. In response, Craig Flemming, Senior Director of Finance for NS Power, indicated that the utility has only been collecting the data required to facilitate the reconciliations recommended by Mr. Madsen since 2009. As such, he stated that the company could provide the information recommended by Mr. Madsen from 2009 onwards. The Board agrees with Mr. Madsen's recommendations and directs NS Power to provide this information from 2009 onwards in its next depreciation study filed with the Board.

3.4.1.3.2 Adjustments to Net Salvage Rates

[167] Mr. Madsen completed a detailed review of the net salvage rates proposed in Appendix "A" of the settlement agreement. Based on this review, Mr. Madsen did not recommend any changes to the proposed net salvage rates. Mr. Madsen stated that there were two primary reasons he reached this conclusion. First, he noted that while some of the proposed net salvage rates may be over or understated, there does not appear to be a clear directional bias in the proposed rates. In effect, he believes that the proposed net salvage rates are within a range of reasonably expected results.

[168] Second, as will be discussed in following sections of this decision, Mr. Madsen has recommended that NS Power adopt the Average Life Group (ALG) depreciation procedure, and that the company make changes to the estimated service lives for several of its asset accounts. If these recommended changes were to be directed by the Board, Mr. Madsen stated that they would result in a gradual and moderate, but not inconsequential, reduction of depreciation expense for NS Power. As such, he recommended that the Board allow the “dust to settle” from those proposed changes and then potentially reassess the proposed net salvage rates as part of NS Power’s next depreciation study.

[169] For the most part, the Board agrees with Mr. Madsen’s conclusion that the proposed settlement agreement net salvage rates are within a range of reasonably expected results. The Board’s agreement applies to all Plant accounts for which settlement agreement adjustments were not made to Gannett Fleming’s estimated net salvage rates, and to the three transmission and distribution Plant accounts to which net salvage rates were adjusted in the settlement agreement. The Board finds the proposed net salvage rates for those Plant accounts to be acceptable. However, for the reasons that follow, the Board has some concerns about the settlement agreement net salvage rate adjustments for Power Production Plant accounts.

[170] The settlement agreement removes archaeological reconnaissance costs from hydro system decommissioning estimates. Based on NS Power’s response to NSEB IR-85, this results in a significant reduction in the related decommissioning cost estimates (when Mersey, Tusket and Wreck Cove are excluded) compared to the estimates upon which Gannett Fleming based its study. The Boreas archaeology report included in

Exhibit N-7 states that in developing archaeological cost estimates associated with decommissioning NS Power's hydro systems, it assumed archaeological reconnaissance would be undertaken for all systems "to identify and delineate real areas exhibiting high archaeological potential, to confirm the results of the background research and archaeological potential modelling, and to document any archaeological resources identified during the background study and/or encountered during the visual assessment, as per existing standards and best practice". In the event that an area was considered to exhibit low archaeological potential, archaeological monitoring could be recommended for the purpose of obtaining additional information and/or to confirm the results of the assessment.

[171] In the case of hydro system partial decommissioning, where removal of structures required for water management is not required, perhaps the related archaeological potential is likely low. If so, an assumption that archaeological reconnaissance costs would not be required might make some sense. However, beyond the settlement agreement itself, there is nothing in the current evidentiary record before the Board to provide justification for such an assumption. Further, Gannett Fleming certainly included archaeological reconnaissance costs in its study to estimate appropriate depreciation rates. This suggests that Gannett Fleming, as NS Power's depreciation expert, believes it is appropriate to include these costs in the related decommissioning cost estimates.

[172] As it relates to the settlement agreement adjustment to remove contingency costs from generation decommissioning cost estimates, the Board refers to NS Power's 2018 Hydro Asset Study (HAS) (filed in NS Power's 2019 ACE Plan proceeding, Matter

M08984). The 2018 HAS is the information upon which Hatch relied upon to update its hydro system decommissioning cost estimates in the current GRA. On page 73 of Appendix B of the 2018 HAS, Hatch states “Contingencies are included in the estimates to provide for costs which cannot be specifically identified at the time of estimate preparation, but which can be foreseen with varying degrees of probability throughout the life of the project – i.e., contingencies are costs that are expected to be incurred”. Based on this statement alone, the Board sees no valid reason why contingency costs should be removed from generation decommissioning cost estimates.

[173] In addition, the Board notes that the thermal Plant, gas turbine Plant, wind production Plant and marine terminal and associated infrastructure decommissioning cost estimates included in the Gannett Fleming depreciation study were developed to an Association for the Advancement of Cost Engineering (AACE) Class 4 level. This Class level aligns with a level of project definition between 1% and 15%. As such, the related decommissioning costs estimates include a contingency allowance of 20% for wind production Plant and 25% for the others. Similarly, the hydro system partial decommissioning cost estimates included in the Gannett Fleming depreciation study were developed to a Class 5 level (per the Yates report filed as Undertaking U-10). This level estimate is typically based on a 0% to 2% level of project definition. The document upon which those cost estimates were developed does not identify the amount of contingency included in the estimates.

[174] Beyond the settlement agreement itself, there is nothing in the current evidentiary record before the Board to provide support to exclude costs of such magnitude from generation Plant decommissioning cost estimates. Further, Gannett Fleming

certainly included contingency costs in its study to estimate appropriate depreciation rates. This suggests that Gannett Fleming, as NS Power's depreciation expert, believes it is appropriate to include these costs in the related decommissioning cost estimates.

[175] The settlement agreement also reflects forecast decommissioning costs for all generation Plant in 2024 dollars (i.e., it removes the effect of inflation to forecast years of decommissioning). In his evidence, Mr. Madsen notes that the collection of net salvage in rates is based on a forward-looking estimate of the cost to salvage the installed assets. That estimate is typically based on historical costs to salvage assets, inflated forward to the future years the costs will be incurred. As stated on page IV-3 of Gannett Fleming's depreciation study, this is, in fact, the methodology employed by Gannett Fleming in the current GRA. This suggests that Gannett Fleming, as NS Power's depreciation expert, believes it is appropriate to include these inflation costs in the related decommissioning cost estimates. Further, beyond the settlement agreement itself, there is nothing in the current evidentiary record before the Board to provide support to exclude inflation costs beyond 2024 from generation Plant decommissioning cost estimates.

[176] The Board also has other concerns about the settlement agreement adjustments made to net salvage rates for NS Power's production Plant assets. First, as identified in Mr. Madsen's evidence, NS Power currently has a significant reserve deficiency in its production Plant asset accounts. A reserve deficiency exists when the book accumulated depreciation reserve balance is below the calculated accumulated depreciation reserve balance. The book accumulated depreciation reserve balance reflects the amount of depreciation already collected in rates from customers, while the calculated accumulated depreciation reserve balance is the amount that NS Power

should have recovered in rates based on the applied depreciation and net salvage parameters.

[177] As identified by Mr. Madsen, NS Power has a \$572,266,492 depreciation reserve deficiency in its production Plant accounts. This suggests that depreciation rates for production Plant assets have already been too low in the past. This difference will eventually need to be recovered from future customers, putting further upward pressure on rates in later years and potentially leading to intergenerational inequity. This is a concern.

[178] The Board is also concerned about the hydro system decommissioning cost estimates included in the depreciation study. As noted previously in this decision, Gannett Fleming's depreciation study and NS Power's proposed depreciation rates have been set using hydro decommissioning cost estimates based on partial decommissioning rather than full decommissioning. NS Power believes this approach is measured and responsible and helps to ensure rates are just and reasonable until there is greater certainty as to whether there is a realistic possibility that decommissioning of the assets, whether full or partial, will actually occur. The Board does not necessarily disagree with this premise. However, even under this approach, the Board is concerned about the accuracy of the hydro system partial decommissioning cost estimates upon which the depreciation study relied.

[179] NS Power stated in response to NSEB IR-85 that its proposed approach represents the lowest estimate of partial decommissioning costs, as it does not include any work on the civil aspects of the hydro systems, which tend to drive most of the decommissioning costs. This is concerning to the Board for two reasons. First, as the

“lowest estimates”, the partial decommissioning costs included in the depreciation study represent the minimum that current customers will pay for the related net salvage values. If partial decommissioning of any of NS Power’s hydro facilities is eventually undertaken, it is very likely that these “minimum” decommissioning costs will increase. If this occurs, the increased costs will be pushed on future ratepayers, resulting in intergenerational inequity and perhaps future ratepayers paying decommissioning costs for assets they may have never used.

[180] Second, the Board notes that the partial decommissioning cost in the Yates report for the Tusket hydro system was approximately \$1.9 million. The Yates report is the document upon which NS Power relied to develop its hydro system partial decommissioning cost estimates for inclusion in its depreciation study. However, because of work currently being undertaken on the Tusket hydro system, NS Power developed a more detailed and updated partial decommissioning cost estimate for Tusket. This updated estimate is roughly \$127.5 million, which is significantly higher than the estimate from the Yates report. This was discussed further during the hearing:

Q. (Murphy) ...There's a big gap in the difference between -- let's just talk about the partial decommissioning costs. There is a big gap in the partial decommissioning costs for Tusket that Nova Scotia Power has developed versus the partial decommissioning costs that the [Yates] Report developed.

I can call up the page if you'd like from the [Yates] Report to show Tusket, but it's a big gap. Do you agree?

A. (MacIntosh) Yes, sir. And I can elaborate on why that is.

Q. Well, I — just let me ask my question first and then —

A. (MacIntosh) Sure.

Q. — you'll see where it goes.

Given that there's a big gap in Tusket between the decommissioning costs that Nova Scotia Power says it's advanced further than all the other costs, how can the Board have any confidence that those other decommissioning costs that are based on the [Yates] Report are appropriate or accurate enough to include in depreciation rates?

A. (MacIntosh) Yes, it's a good point, Mr. Murphy. We did respond to this in IR-85, Part B that's in 27, Board IR, it's that same IR we had up, but we did recognize that the partial decommissioning costs that were included would be the minimum. So in the terms of Tusket, the scope of work for partial decommissioning was a different scope of work than we would have included in the scope of work for the partial decommissioning estimates of the other sites.

So in terms of Tusket, the Tusket partial decommissioning estimate includes civil works, so includes work with water retaining structures, dispatches associated. The partial decommissioning estimates that we've submitted for the GRA purposes have a much minimum — a smaller scope of work.

So your point is that, yes, it is smaller based on the scope of work that we did include.

Q. So it'd be fair to say that the partial decommissioning costs for these other smaller assets would probably be a lot higher.

A. (MacIntosh) If there was the requirement to expand the scope of work beyond the generator and the turbine and the runner. So if you could just decommission the site and the powerhouse without having to expand the footprint in the civil structures, then it could be reasonable. But if there was a requirement to expand the scope like Tusket, then obviously the investment would be higher.

[Transcript, January 7, 2026, pp. 299-302]

[181] The Board understands the position expressed by NS Power during this exchange. However, given the experience at Tusket, the Board takes no comfort that other hydro systems will not encounter similar issues as Tusket under a decommissioning scenario. In that event, partial decommissioning costs for other hydro systems would be much higher than the costs currently included in NS Power's depreciation study. Again, the increased costs would be pushed on future ratepayers, resulting in intergenerational inequity and perhaps future ratepayers paying decommissioning costs for assets they may never have used.

[182] Another issue of concern to the Board relates to the aftermath of a partial decommissioning scenario. In the partial decommissioning approach put forward by NS Power, structures required for water management, such as dams, spillways and gates, would remain in place while the related hydro system would no longer generate power. These structures would continue to incur sustaining capital upgrade costs and continued

maintenance costs to ensure they remain safe. However, the assets themselves would no longer be considered “used and useful” from a ratepayer perspective. This raises the issue of who would be responsible for the on-going costs for assets no longer used and useful – ratepayers, NS Power shareholders or others who may benefit from maintaining this infrastructure? This was discussed during the hearing:

Q. (Murphy) Would it be fair to say in the partial decommissioning scenario that there would be ongoing O&M costs and capital sustaining costs associated with any of the assets that are not decommissioned, particularly the dams, spillways, water retaining structures?

A. (Williams) Yes, even if there wasn't any generation coming from those sites, Nova Scotia Power, if they owned those assets were still required to maintain the safe operation of those assets and there would be an OM&G costs associated with it.

Q. And ongoing sustaining capital costs as well.

A. (Williams) Correct.

Q. And would you agree that once those assets are partially decommissioned they are no longer used and useful?

A. (Williams) Yes, I think generally speaking, sir, we would agree with that, and I think that gets to the point of where we're going with some of these hydro discussions, that there needs to be a broader discussion of how these are handled in the future, and if they are to be decommissioned whose responsibility ultimately that would be both as in the decommissioning phase of them, but also after that in maintaining them.

So I would agree that there's a — an inconsistency, perhaps, with traditional or normal utility practice if those were to be partially decommissioned and retained as assets of the utility.

Q. Right. If they were no longer used and useful and there was any further costs, ongoing O&M costs, capital sustaining costs as a no longer used and useful asset, any of those costs would typically be the responsibility of Nova Scotia Power and shareholders. Correct?

A. (Williams) And that's why I say I think traditionally our normal course, but I think there would need to be a recognition that those assets are not the same as -- and this is the discussion I think mainly with some of the larger assets, where if those structures were to be retained whose responsibility ought those to be. It's not the same as a generation asset in the middle of a field where you just reclaim it and it becomes brownfield and you can walk away from it, or sell the land, it's different than that. I think there would need to be a broader discussion of how those assets were handled.

Q. So you're suggesting that perhaps ratepayers should be on the hook for some costs associated with assets that they get absolutely no benefit from.

A. (Williams) So I wouldn't put it like that, sir, but that probably doesn't surprise you. I think in that scenario there would be a benefit to ratepayers, which is we would be doing

something that, you know, otherwise if we fully decommissioned it, the partial decommissioning would be a lower cost to customers. So there would be a benefit to customers, but not in the sense of it's providing a service to customers, but the benefit would be there.

And I think when I say, you know, a broader discussion, I think it's a broader discussion within the province of how those would be handled if we were in a position where we were partially decommissioning assets, and to your point, which is a good point, no longer producing electricity or providing a traditional utility function, but there would be a benefit.

[Transcript, January 7, 2026, pp. 305-308]

[183] Finally, the Board understands NS Power's rationale for including partial rather than full hydro system decommissioning costs in its depreciation study. Whether full decommissioning is even possible or feasible at some of NS Power's hydro systems is uncertain. Nonetheless, there is no certainty that partial decommissioning for some systems will prove to be the preferred choice over full decommissioning. In Undertaking U-11, NS Power provided a copy of its depreciation calculations under the assumption that full decommissioning of hydro systems would be required. The Undertaking reveals that under a full decommissioning scenario for all hydro systems excluding Mersey, Tusket and Wreck Cove, depreciation rates would be approximately \$65 million higher than those in the settlement agreement.

[184] In the Board's opinion, the settlement agreement adjustments to production Plant net salvage rates appear simply as a means to reduce the effect of depreciation on revenue requirement in the short term, which by implication is at the expense of future customers. The self-interest of some parties to the agreement in deferring costs to future customers is understandable, but it does create intergenerational inequity concerns.

[185] As identified in NS Power's response to NSEB IR-87, the net effect of settlement agreement adjustments to NS Power production Plant net salvage rates results in a revenue requirement reduction of \$10.6 million in 2026 and \$11.7 million in

2027. If the Board were not to approve these adjustments, it would result in an average rate increase of roughly 0.5% to the rates filed in the settlement agreement. This would be an unfortunate impact, but the Board believes it could address intergenerational concerns.

[186] The Board notes that implementation of other depreciation related issues it is addressing in this decision could more than offset this increase. However, all of this must be considered in the context of the status of NS Power's intended securitization of assets within the scope of the DDA. With securitization remaining uncertain, as explained later in this decision, a change in NS Power's proposed depreciation expense from what is proposed in the application would affect its funds from operations: debt credit metrics even further. This could increase the risk of having credit rating agencies lower NS Power's credit rating to "junk" status. As noted in Morrison Park's evidence, this would have serious long-term cost consequences resulting in higher costs for ratepayers.

[187] Further, at this point there remains considerable uncertainty related to current decommissioning cost estimates for these assets. This is particularly true for NS Power's hydro assets, where it remains uncertain whether these assets will eventually undergo partial or full decommissioning, or even be decommissioned at all. As noted above, the Board has directed NS Power to address this issue before its next GRA. Given this uncertainty, the potential impact, if any, of assumed production Plant net salvage rates on future ratepayers is unclear. In this circumstance, the Board accepts the proposed settlement agreement adjustments to net salvage rates for NS Power's production plant accounts. Therefore, for the purposes of the current GRA, the Board also

finds that the proposed settlement agreement changes to the net salvage rates and decommissioning costs are appropriate.

[188] This notwithstanding, as NS Power rightly noted in its closing submissions, there currently remains no settled policy or a multi-stakeholder framework for determining whether, when, or how full or partial decommissioning of hydro facilities should occur, nor who would ultimately bear responsibility. NS Power further stated:

... NS Power views the present proceeding as a necessary first step in advancing the conversation of the future of hydro in the province and the Company acknowledged its responsibility to initiate a broader, structured discussion involving regulators, government, and other relevant stakeholders. At the same time, the Company was clear that neither the outcome nor the timeline of that process is within its sole control. Further, in the Nova Scotia Independent Energy System Operator-led Integrated Resource Plan (IRP), NS Power's existing hydroelectric units will be evaluated based on historical hydrology, operational and environmental constraints, physical limitations, and their energy and capacity contributions which will help inform this important discussion.

In these circumstances, NS Power submits that the prudent course is to proceed on the basis proposed in this Application, while establishing a forward process, including appropriate Board oversight and reporting, to ensure that this important and complex issue impacting all Nova Scotians is addressed in an orderly, transparent, and coordinated manner.

[NS Power Closing Submissions, pp. 53-54]

[189] The Board agrees with NS Power's proposed approach to address this issue. If this broader interested party engagement demonstrates decommissioning of hydro assets is a potential path or option, then the relevant costs can be included in the revenue requirement to be approved in NS Power's next general rate application. The Board directs NS Power to undertake this interested party engagement process, with an ideal target completion date in advance of NS Power's next GRA. During this process, the Board directs NS Power to file regular update reports with the Board every six months, beginning October 1, 2026.

3.4.1.3.3 Adjustments to Estimated Asset Average Service Lives

[190] In his evidence, Mr. Madsen proposed a number of changes to Gannett Fleming's recommended estimated asset average service lives. This is discussed in more detail in section 3.4.3 of this decision. For the reasons described in that section, the Board does not approve Mr. Madsen's proposed service life adjustments. This notwithstanding, the Board notes that the proposed settlement agreement change for Account 353 (Transmission Station Equipment) moves the estimated average asset service life for that account closer to that recommended by Mr. Madsen. The Board also notes that although Mr. Madsen recommended no change to the average asset service life for Account 390.10 (General Plant Structures and Improvements), he did state that peer data supports a life extension to some degree. The Board observes that the proposed settlement agreement change for this account does, in fact, extend the service life slightly.

[191] Considering the above, for the purposes of the current GRA, the Board finds that the proposed settlement agreement changes to the average service lives for NS Power's asset Account 353 and Account 390.10 are appropriate.

3.4.2 Calculation of Depreciation Expense (ELG vs. ALG)

[192] As noted previously, NS Power's updated depreciation study has used the Equal Life Group procedure to calculate proposed depreciation rates. NS Power has used the ELG procedure for the past 32 years, and Gannett Fleming has recommended its continued use. 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. The procedure relies on estimating retirement dispersion patterns and applying lowa 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.

[193] An alternative to the ELG procedure is the ALG procedure (also known as the Average Service Life procedure). ALG is a procedure that 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.

[194] Regardless of the depreciation procedure selected, the purpose of the exercise is to depreciate the same amount of investment over the expected life of an asset. 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.

[195] Gannett Fleming's depreciation study states that the ELG procedure provides a better match of depreciation expense and loss in service value than the ALG procedure. In Gannett Fleming's opinion, 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. In comparison, Gannett Fleming notes that a characteristic of the ALG procedure is that the cost of Plant retired prior to average life

is not fully recouped at the time of retirement, whereas the cost of Plant retired after average life is more than fully recouped. However, over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

[196] In his evidence, Mr. Madsen acknowledged that both ELG and ALG are acceptable and appropriate procedures to determine depreciation expense. However, he argued that ALG provides for a more gradual, moderate and equitable recovery of depreciation. He believes this is important, as it allows for some moderation of potential changes in the depreciation recovered over the life of the assets, particularly as lives are lengthening. Mr. Madsen believes this “lengthening” is becoming common, particularly for transmission and distribution assets, where utilities are replacing significantly older assets with much newer assets that often have much longer service lives.

[197] Mr. Madsen contends that ELG front-loads depreciation expense and is highly sensitive to changes in asset lives and retirement assumptions. He stated that a common argument against ELG, which he agrees with, is that it ignores that the benefits of most electric utility assets with regular maintenance do not decline considerably in later years as the ELG procedure suggests. As asset lives lengthen over time, Mr. Madsen argued that ELG will over-recover depreciation early, requiring later corrections. He stated that this can create intergenerational inequity, where current customers pay more than their fair share of depreciation costs while future customers pay less.

[198] Mr. Madsen’s evidence describes what he believes to be the pros and cons of the ALG and ELG procedures. The Board has summarized this 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: <ul style="list-style-type: none"> • 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.

[199] Mr. Madsen does not accept that NS Power’s use of the ELG procedure inherently provides a better match between depreciation expense and loss in service value than the ALG procedure. Therefore, Mr. Madsen has recommended that NS Power

move to using the ALG procedure for all assets. He is supportive, however, of NS Power continuing to use the remaining life technique. Mr. Madsen contends that ALG is preferred to ELG because it better protects against over-collection, reduces volatility, and avoids unfair cost shifting between customer generations. In response to Emrydia IR-27, NS Power provided the following table depicting the change in 2026 and 2027 depreciation rates if it used the ALG procedure rather than ELG:

Depreciation and Accretion Expense				
(\$ Millions)	Per GRA Settlement Agreement		Per Depreciation Rates calculated under ALG	
	2026	2027	2026	2027
Steam	48.0	49.9	48.7	50.6
Gas Turbine	9.9	10.6	8.9	9.6
Wind Turbine	13.3	13.3	13.3	13.3
Hydro	16.6	17.3	17.9	19.1
Solar	0.1	0.1	0.1	0.1
Transmission	47.7	52.1	46.7	51.1
Distribution	85.4	89.6	64.6	67.8
General Property	61.5	67.9	59.0	65.0
Total	282.4	300.8	259.1	276.5

[Exhibit N-31, Response to IR-27]

[200] During the hearing, however, Mr. Flemming confirmed that the above table does not provide a true “apples to apples” comparison. Specifically, he noted that the ALG rates do not reflect the depreciation related adjustments made in the settlement agreement. These adjustments would further increase the difference between the two methodologies by approximately \$20 million in each of 2026 and 2027. As such, including the settlement agreement adjustments, Mr. Flemming noted the ALG rates would be approximately \$40 to \$45 million lower than those under the ELG. The rates for both procedures also assume the securitization of the assets within the scope of the DDA will proceed.

[201] During the hearing, Mr. Flemming indicated that a \$20 million reduction in annual depreciation expense would equate to a one-time pre-tax decrease of roughly 1% in average rates.

3.4.2.1 Findings

[202] John Wiedmayer, of Gannett Fleming, and Mr. Madsen 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.

[203] Mr. Wiedmayer and Mr. Madsen also agree that the majority of North American electric utilities use the ALG procedure. However, both also noted that ELG is an accepted procedure by a number of utility regulators. Mr. Madsen stated that the ALG procedure is much more common in the United States. He also referenced several recent cases where requests to convert from the ALG to ELG have been denied. These include Manitoba, Ontario, New York, Mississippi, as well as other jurisdictions. Mr. Wiedmayer stated that ALG has a longer acceptance primarily due to the fact that it offered a simpler means to complete depreciation related calculations. However, with the advent of today's modern computers, ELG calculations have become easier to complete, resulting in more use of the procedure. He also noted that ELG is currently used in Alberta and Newfoundland. His evidence also indicated that ALG is used by Maritime Electric in Prince Edward Island.

[204] For this GRA, NS Power submitted that it has appropriately applied the ELG procedure using the straight-line method, as it has done previously for over 30 years. The

company believes ELG is superior to ALG as its use has and continues to lower NS Power's rate base and thus, financing costs at a more accelerated pace, and the data used reflects real retirement data experienced by the company. In its closing submissions, NS Power has framed the argument over which procedure is most appropriate as follows:

Overall, the difference between the witnesses is not whether judgment is required, but whether a calculation procedure that explicitly incorporates utility-specific retirement experience by asset age is preferable, on balance, to one that relies on averages, and further the degree to which the resulting impact on rate base ought to be a consideration in choosing the appropriate calculation procedure.

[NS Power Closing Submissions, p. 19]

The Board will first address the issues raised in NS Power's framing. The Board will then address intergenerational equity, which it believes is also an important issue in assessing ALG vs. ELG.

[205] As it relates to a procedure that uses utility-specific retirement experience, in his hearing testimony Mr. Wiedmayer stated that his depreciation analysis relied on NS Power's actual retirement and aged data wherever reliable records exist. He identified this period as beginning approximately in 2009, when NS Power started recording age-at-retirement information. He explained that retirements from that time forward include both vintage year and retirement year and, therefore, constitute true aged data that is used directly to inform survivor curve selection and service life estimates. For earlier years and older vintages where fully aged data records do not exist, he testified that standard "simulated aging" techniques were used to supplement the record. He characterized this as a common and unavoidable feature of long-lived utility Plant.

[206] Mr. Wiedmayer emphasized that simulation techniques are designed to reasonably approximate asset age distributions and retirement patterns when direct data are unavailable. In addition, he noted that simulated data do not displace actual NS Power

aged or retirement data where it exists but instead fill unavoidable gaps in the historical record. He asserted that the combined use of observed and simulated data is consistent with accepted depreciation practice and sufficient to support the application of the ELG procedure.

[207] In his testimony, Mr. Madsen acknowledged that the use of simulated data is preferable to relying solely on unaged data, and he cited the National Association of Regulatory Utility Commissioners (NARUC) Manual to confirm that statistical aging techniques are widely accepted in regulatory practice. However, he also emphasized that simulated data is inherently an approximation, depends heavily on assumptions about initial age distributions and survivor curve shapes, and may smooth or predetermine results in ways that mask true retirement behavior. Mr. Madsen's core concern was not that Gannett Fleming's use of simulated data is improper, but that placing significant weight on that simulated data, particularly combined with the ELG procedure, increases the risk of error.

[208] While acknowledging that ELG is often described as aligning depreciation more closely with retirement patterns, Mr. Madsen argued that this claim depends on the reliability of retirement data. Specifically, he contends that when retirement ages are simulated rather than observed, as is the case for much of NS Power's Plant data, ELG's greater sensitivity to this data can create an appearance of precision that is not grounded in actual service value loss. Mr. Madsen testified that in such circumstances, ALG's smoother allocation of depreciation may provide an equally reasonable and, in his view, more prudent approximation of service value consumption. This is because it avoids over-weighting of assumptions embedded in simulated data and because ALG is less sensitive

to the shape and timing of assumed retirement curves. In effect, Mr. Madsen does not accept “better matching” as an advantage of ELG. Instead, he framed it as a conditional claim that weakens when based on simulated plant data rather than long-standing observed experience.

[209] Considering the above, the Board does not believe that Mr. Madsen’s is suggesting that ALG offers a theoretically superior mathematical calculation of depreciation expense vs ELG. Instead, he argues that in the absence of a solid foundation of actual observed aged asset data, the ELG procedure exacerbates the potential error in calculating depreciation expense when simulated aged data is relied upon. This was discussed further in the hearing:

BY MEMBER MURPHY: ...can you tell me why the ALG procedure doesn’t exacerbate the potential errors associated with using simulated age data in the same way that the -- that you claim the ELG procedure does?

A. (MADSEN) Certainly. So again, if the simulated age data does not accurately reflect the actual retirement pattern of those assets -- and they wouldn’t because the simulated data is a guess, is a best guess. And again, going back to the example we just walked through, it -- the ELG procedure’s going to be based off of those specific datapoints that are simulated.

If those datapoints are incorrect, the ELG procedure is going [to] accelerate depreciation based on the assumption that those datapoints are correct, and that is where the error comes in. Whereas the Average Life Group, again, does not depreciate based on that curve; it depreciates on the assumption that there will be an average amount of depreciation taken in each year.

And that’s why when there’s a variation from year to year in those datapoints, the Average Life Group procedure tends not to overemphasize or put undue reliance on that variation, particularly if there is a risk that the age data that you’re relying upon in this case, the simulated age data, might be incorrect.

I know during the hearing, Mr. Murphy, you looked at some examples in other cases and other jurisdictions. I filed some depreciation studies. And I think the big question that comes to mind is, when you look at the experience in other jurisdictions, why is Nova Scotia Power based on its simulated data seeing significantly lower lives than all the other utilities, at least than I have been reviewing, and across many accounts.

And you need to ask yourself, and I’ve asked myself the same question, is there any underlying force of retirement in Nova Scotia Power that is so great that makes it just tough to do business in Nova Scotia for an electric utility, greater forces of retirement that are all negative rather than some that are positive. I can’t come up with any, and that leads

me to believe that the simulated retirement data that the company's relying upon which is informing the ELG estimates is potentially causing this exacerbated error.

[Transcript, January 12, 2026, pp. 1142-1145]

[210] In this exchange, Mr. Madsen refers to how NS Power's estimated average asset service lives for many accounts, based on its simulated data, are much lower than other peer utilities. This is discussed in more detail in section 3.4.3 of this decision. Nevertheless, a summary of the analysis completed by Mr. Madsen shows NS Power's applied for average service lives are generally lower than those used in New Brunswick, Prince Edward Island and Newfoundland, jurisdictions that are generally subject to similar climate and operating conditions as Nova Scotia.

[211] In his testimony, Mr. Wiedmayer outlined a number of reasons why a peer utility can have survivor characteristics and average service lives that are different than NS Power's. These include differences in capitalization policies, differences in maintenance practices, and differences in the type of structures that are in specific asset accounts. The Board understands these differences but still finds Mr. Madsen's evidence persuasive. Specifically, the Board remains concerned that NS Power's lack of a solid underpinning of true aged data, and related use of simulated data in combination with ELG, is perhaps leading NS Power to arrive at certain conclusions that would not be supported if actual true aged data were present. In particular, the simulated data may be skewing calculations to result in shorter estimated asset service lives, particularly when compared to NS Power's peers. If this is occurring, the use of lower service lives alongside the use of the ELG procedure will result in more aggressive depreciation estimates. In turn, this can lead to intergenerational equity concerns and the need to update depreciation rates more frequently.

[212] NS Power has also submitted that when choosing an appropriate depreciation procedure, the impact on rate base should be a consideration. In their hearing testimony, both Mr. Wiedmayer and Mr. Madsen addressed the interaction between depreciation and return on rate base.

[213] Mr. Wiedmayer testified that while ELG produces higher annual depreciation expense and revenue requirements than ALG in earlier periods, it also reduces rate base more quickly than ALG. Over time this results in lower return on rate base in later periods and a crossover point when depreciation and return on rate base are considered together. For periods beyond this crossover point, the annual revenue requirement under ELG becomes lower than under ALG. In Undertaking U-12 [Exhibit 59(i)], Mr. Wiedmayer filed a copy of an Excel model that he prepared to provide an example demonstrating this crossover point concept between ELG and ALG. The model was created using company-specific (UGI Utilities, Inc.) data. UGI Utilities, Inc. is a combined electric/gas utility with operations in Pennsylvania, Maryland and West Virginia.

[214] Mr. Madsen did not dispute the underlying mechanics described by Mr. Wiedmayer. Under questioning from NS Power counsel, he acknowledged that changes in depreciation expense necessarily affect rate base and related return, and that lower depreciation increases rate base and the return component of revenue requirement. He further acknowledged that collection of lower depreciation expense under ALG would also increase debt costs to finance the rate base differential. Mr. Madsen also confirmed that the analysis presented in his evidence regarding ALG vs. ELG only considered the impact on depreciation expense (i.e., it did not consider the impact on rate base and financing costs). As Mr. Madsen noted, the sole purpose of his testimony is to provide a

recommendation to the Board that “gets depreciation right”, recognizing there are going to be other impacts regardless of which depreciation procedure is selected.

[215] Nevertheless, under questioning from the Board, Mr. Madsen provided the following commentary on his analysis of Mr. Wiedmayer’s ALG vs. ELG crossover model filed in Exhibit 59(i):

MADSEN: ... The more important issues are the fact that the analysis is not based on Nova Scotia Power evidence. When I looked at the more detailed spreadsheet and the USA accounts that were informing the spreadsheet the main USA accounts are 376.1, 376.3, and I could name them, there’s six accounts, they’re all gas utility accounts. They make up roughly 84 percent of the total asset base, and those are services, gas mains, and things of that sort. They’re not electric utility assets akin to what Nova Scotia Power operates. So it’s like comparing apples to oranges. And I couldn’t, based on my review, actually identify any accounts in this analysis that were electric utility accounts like a tower conductor or even production plant.

The example also assumes a return of 8 percent. A return of 8 percent is not reflective of Nova Scotia Power’s weighted average cost of capital, which is somewhere just above 6 percent. A higher return in this analysis is going to dramatically -- quite dramatically overstate the revenue requirement related to this difference that you’re seeing in the difference on rate base.

The starting point of the analysis again is for utilities gross plant in service that is not Nova Scotia Power’s. If I were to update that starting point to be Nova Scotia Power’s gross plant in service of I think roughly eight point something billion dollars and then used the growth rate that I’ve seen for Nova Scotia Power over the last three years, which has been averaging roughly 3 percent since close to 2024, the rate of growth in that cost increases quite significantly. That’s another issue.

The other -- the analysis also ignores income tax sometimes, which can, in several ways, cause the ALG procedure to look like it is creating more revenue than it actually is. Depreciation, when included in revenue, is a taxable item, and the ELG procedure has a higher level of depreciation expense.

I apologize. There’s a number of issues. The other issue is the exhibit includes a very, very low composite depreciation rate, somewhere in the range of about 2 percent. While I appreciate that might reflect the gas utility assets that were being studied by Gannett Fleming in this limited example, the applied-for depreciation rate for Nova Scotia Power is somewhere closer to 3.37 percent on a composite basis. So quite a lot higher than 2 percent. When you use that rate, as well as the actual applied-for or recalculated average life group rate, it again materially alters the results of this analysis by changing the amount of depreciation expense calculated.

And I’m almost done.

The composite remaining life is also incorrect in this analysis based on what is the composite remaining life for Nova Scotia Power. So fundamentally the analysis is not a Nova Scotia Power focused analysis and is providing a result that makes -- that is, in my mind, misleading.

The final point that I would make before I kind of conclude is that the analysis is out over to 2050. Whenever I do an analysis that extends beyond two, to three, to four or five years I do a net present value calculation. So if you look at it on a -- and ignoring the net present value with future cash flows it suggests that based on the two scenarios the ALG procedure will recover \$20.3 million more in revenues. Ignoring all of the issues that I just outlined, \$20.3 million more revenues than the ELG procedure. But on a net present value basis, using Nova Scotia Power's weighted average cost of capital it is actually unfavourable to the equal life group procedure to the amount of \$83.5 million. So it swings by about \$100 million the other way. And again if you're looking out into the future at the future impacts that customers are going to pay then you need to analyze that scenario on a net present value basis.

Changing the various variables -- and again my big caveat would be I did not do one of these analysis for the reasons I stated in questioning earlier. It is very difficult to present an analysis like this that is going to be perfectly accurate and reflect the future. If you have -- if you hold several assumptions though true, if you assume a growth rate of 2 percent for Nova Scotia Power, if you assume a weighted average cost of capital of about 6.15 percent, around that range, which reflects the applied-for average cost of capital, and if you assume the growth rate -- or sorry, the depreciation rate in this analysis and change the variables to reflect what Nova Scotia Power actually has invested, there is no crossover point between the ALG and ELG procedures in the next -- between now and 2050. There's not.

If you increase that growth rate to three percent, which again is more closely reflecting the Nova Scotia growth rate in recent years, there will not be a crossover point for a very long time. I don't know when, but it won't be -- certainly well beyond 2050. [Emphasis added]

[Transcript, January 12, 2026, pp. 1171-1176]

[216] In essence, Mr. Madsen does not dispute that over the long-term the total amount of revenue requirement that is collected under ALG will be higher than the total amount of revenue requirement that is collected under ELG, due to increased financing costs. What he does dispute, however, is the timing of when the crossover point happens, as well as the magnitude and relevance of the difference on a net present value (NPV) basis.

[217] The Board recognizes that Mr. Madsen did not complete a formal NPV analysis of Mr. Wiedmayer's ALG vs. ELG crossover model. Nonetheless, the Board finds his related hearing testimony to be convincing. First, even with the model's shortcomings as they relate to the lack of relevant NS Power specifics, the Board notes that the additional \$20.3 million collected under ALG would represent only 0.15% of total revenue

collected over the model's 25-year period. So even if the Board were to accept the model as a valid example representing the impact of ALG vs. ELG on NS Power (which it does not), the Board would find this difference immaterial.

[218] The Board agrees with Mr. Wiedmayer that there is a crossover point between ALG and ELG after which the annual revenue requirement under ELG becomes lower than under ALG. However, the Board also agrees with Mr. Madsen that as NS Power continues to grow its rate base (which it certainly intends to do at least over the current GRA test period), depreciation expense will increase to a greater extent than the associated increase in return on rate base. As such, as long as NS Power's rate base continues to grow, the crossover point between ALG and ELG will occur further into the future. The Board does not generally set rates based on long-term convergence of illustrative models. Instead, the Board sets rates on the revenue requirements that customers face in the periods immediately ahead over the test period. Nevertheless, on an NPV basis, the shifting of the crossover point more into the future will further favour the ALG procedure by having a lower NPV of revenue requirements than ELG.

[219] Another issue that the Board considers important when deciding whether it is best 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 intergenerational equities between generations of customers to try and ensure, as best as possible, that the customers who use the assets pay for the assets.

[220] Mr. Wiedmayer addressed intergenerational equity in the context of matching depreciation expense to the pattern of service value consumption reflected in observed retirement dispersion. He acknowledged that ELG and ALG produce different

timing profiles in earlier and later periods. However, he stated that the ELG procedure is designed to allocate depreciation in a manner consistent with the statistical pattern of retirements within a life group, and that doing so promotes equity by aligning cost recovery with the period over which assets provide service. As such, he does not characterize ELG as shifting costs unfairly to current customers. Instead, he noted that ELG distributes depreciation consistent with retirement behavior and accepted depreciation practice, which he views as supporting appropriate cost allocation across customer generations.

[221] Mr. Madsen believes that ELG front-loads depreciation expense relative to ALG, resulting in higher depreciation rates in earlier periods and lower rates in later periods. His primary intergenerational equity concern, therefore, is that it accelerates cost recovery, meaning current customers pay more than they should and future customers pay less. This concern mainly stems from his assertion that ELG's earlier-period expense recognition does not appropriately reflect NS Power's actual consumption of asset service value, which for a number of asset accounts is not based on true aged data. He also noted that as asset lives lengthen over time, which he stated is generally occurring in the electric utility industry, ELG will over-recover depreciation early, creating similar intergenerational equity concerns. Considering the context of the ALG/ELG crossover point, Mr. Madsen also expressed concern that customers paying higher rates in the early years under ELG may not be the same customers who benefit after the crossover. Overall, he argued that the ALG procedure is less aggressive on the front end and provides a more stable depreciation recovery pattern, thereby lessening the risk of intergenerational inequity.

[222] During the hearing, the NS Power depreciation panel raised a further point related to potential intergenerational equity concerns under the ALG procedure. Specifically, the panel noted that under ALG, ratepayers may end up paying for assets that are no longer used and useful. Mr. Madsen acknowledged that this premise could be true, but that it could also occur under ELG when the amount of depreciation expensed does not perfectly reflect the actual consumption of assets over time. He then walked through an example of how this could happen, referencing Figure 17 in his evidence [Exhibit N-34]. Mr. Madsen noted that the distinguishing features between ALG and ELG are that ELG accelerates depreciation in the early years compared to ALG, and then at the other end potentially draws it out for a longer period, although at a much smaller rate.

[223] Based on the discussion above, 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. The Board finds that this is particularly relevant in circumstances where asset service lives are extending over time. The Board believes this is a trend that is occurring in the electric utility industry given technological advances in assets themselves, as well as improving asset management measures undertaken by utilities. Indeed, in recent ACE Plan proceedings, NS Power has touted its asset management plans, procedures and mechanism, the use of which often result in the lives of assets being extended to the benefit of customers.

[224] 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 NS Power's assets over time while minimizing

intergenerational equity 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.

[225] In this context, in assessing the choice between ALG and ELG for NS Power, the Board finds Mr. Madsen's evidence and testimony persuasive. Mr. Madsen acknowledged that both methods are accepted depreciation procedures and recover the same total depreciation over the full-service life of the utility's assets. However, he also identified material differences in timing, sensitivity, and risk between the procedures. He explained that ALG is less sensitive to short-term fluctuations in retirement assumptions and simulated plant data, while the use of ELG for NS Power places greater weight on such data. He also noted the intergenerational equity risks associated with ELG accelerated recovery in earlier periods. Mr. Wiedmayer characterized these effects as neutral timing differences that can be addressed through ongoing depreciation studies.

[226] The Board does not necessarily disagree with Mr. Wiedmayer. However, based on the evidentiary record before it, the Board gives more weight to Mr. Madsen's position that greater sensitivity and front-loaded recovery under ELG increases uncertainty and volatility for NS Power customers, particularly where long-term, true aged plant data is not yet available for a number of NS Power accounts. In these

circumstances, the Board considers ALG to be an approach that better balances accuracy, gradualism, rate stability, depreciation vs return on rate base interactions, and intergenerational equity fairness. Notwithstanding this, the Board is not making a finding that ELG is inappropriate.

[227] The change to the ALG procedure recommended by Mr. Madsen would result in lower rate increases for NS Power ratepayers over the 2026/2027 test period. If all other things remain per the settlement agreement, the change would result in a one-time pre-tax decrease of roughly 1% in average rates. However, the reduction in related depreciation expense resulting from any change to ALG must also be considered in the context of the status of NS Power's intended securitization of assets within the scope of the DDA. With securitization remaining uncertain, as explained later in this decision, a change in NS Power's proposed depreciation expense from what is proposed in the application would affect its FFO:Debt credit metrics even further. This could increase the risk of having the credit rating agencies lower NS Power's credit rating to "junk" status. As noted in Morrison Park's evidence, this would have serious long-term cost consequences resulting in higher costs for ratepayers.

[228] Therefore, for the purposes of the current GRA, the Board will not direct NS Power to adjust its depreciation procedure from ELG to ALG. Nevertheless, as noted previously, based on the evidence in the current proceeding, the Board is persuaded that the ALG procedure likely offers a more appropriate means for NS Power to determine depreciation expense. The Board believes this needs to be further considered.

[229] To give some historical context, in April 2003, NS Power filed a depreciation study with the NSUARB that recommended an increase in annual depreciation expense.

A consultation process followed, which culminated in the development of a settlement agreement that was unanimously supported by the intervenors in that proceeding. The settlement agreement on future depreciation rates was adopted as a “black box” settlement. In that type of agreement, parties settled on an amount without fully agreeing to the way the amount was derived. The settlement agreement was approved by the NSUARB in its Decision dated November 21, 2003. Similarly, in November 2010, NS Power filed an updated depreciation study with the NSUARB and requested approval of new depreciation rates. The parties to that proceeding once again reached a “black box” settlement agreement that the NSUARB approved in May 2011.

[230] In both proceedings, the settlement agreements were reached in due course after a full evidentiary record was filed with the Board. Those records included information requests filed by parties, evidence filed by Board Counsel consultants, and, in the 2010 depreciation proceeding, evidence filed by experts retained by intervenors. Specifically in the 2010 depreciation proceeding, the issue of ALG vs. ELG was raised by Board Counsel consultants and the expert hired by NewPage Port Hawkesbury Corp. and Bowater Mersey Paper Company Limited. Both these experts recommended that NS Power move to using the ALG procedure. However, given the nature of the “black box” settlement agreements in those matters, and the Board’s subsequent approvals, the Board did not opine on the use of ALG vs. ELG in those proceedings.

[231] In the current proceeding, NS Power submitted that it has appropriately applied the ELG procedure for over 30 years. However, as Mr. Wiedmayer acknowledged during the hearing, there is a correlation between NS Power using ELG over this period and the lack of depreciation studies that have been filed by NS Power over the same

timeframe. Further, given the nature of the current GRA settlement agreement approach, the Board is unaware of the extent to which ALG vs. ELG was discussed, or even considered, by the parties to the agreement.

[232] The current GRA is the first time the ALG vs. ELG issue has been put before the Board since the 2010 depreciation study. In addition, the Board's approval of the "black box" settlement agreement in that proceeding did not result in a specific Board finding on whether ALG or ELG was the most appropriate depreciation procedure for NS Power to use moving forward. Nor did the Board's approval of the 2003 depreciation study "black box" settlement agreement result in such a finding. Further, as it relates to NS Power's assets and their related depreciation expense, a lot has changed since 2003. These include such items as legislative changes requiring certain assets to be retired by 2030, technological advancements to improve/extend asset lives, climate change and an evolving NS Power generation asset mix.

[233] Given this background, the Board believes that further testing of ALG vs. ELG, to confirm which methodology is most appropriate for use by NS Power, needs to be addressed as part of the company's next depreciation study. NS Power agreed to this in its reply submissions. Generally, the Board would expect NS Power to file a new depreciation study every five years. However, in this case, the Board believes that waiting five additional years to further examine the use of ALG vs. ELG is too long. As such, the Board directs NS Power to file an updated depreciation study with its next general rate application. The Board believes this earlier study is further warranted by the changing make-up of NS Power's generation assets, as well as its plans to construct significant new transmission assets in the near future. The timing will align more closely with

completion of the IESO Nova Scotia's currently underway IRP. It will also allow NS Power to build up several more years of true aged asset data.

[234] Within the next depreciation study, the Board fully expects that the use of ALG will be more closely examined and assessed in detail by NS Power. As part of its ALG vs. ELG assessment, the Board expects NS Power to address issues including, but not limited to:

- The interaction between depreciation expense and return on rate base;
- The extent to which actual true aged data has been used;
- A NS Power specific ALG vs. ELG cross-over point analysis;
- Comparison to other peer utility data, particularly related to actual age data, the retirement patterns experienced by those utilities, recommended asset service lives, and a description of what forces of retirement those utilities have that are consistent with those of NS Power;
- Identification of specific factors in Nova Scotia that differ from other peer utilities that would lead to a higher rate of retirement or greater forces of retirement;
- The book accumulated depreciation reserve balance and calculated accumulated reserve balance under both the ALG and ELG procedure;
- An evaluation of whether a change to the ALG procedure would violate the principles of gradualism and moderation, and whether a "phasing-in" of ALG would be appropriate; and
- The proposed depreciation by asset account under both ELG and ALG procedures.

3.4.3 Asset Average Service Lives

[235] Section 3.4.1.2 of this decision describes Gannett Fleming's approach to estimating average asset group service lives in its depreciation study. Mr. Madsen described a similar approach in his evidence:

Both the ALG and ELG procedures rely on the selection of an Iowa curve based on several factors, including but not limited to:

- Visual and mathematical fit of the observed retirement data to the selected survivor curves.
- Peer data on the average service lives and survivor curves used in other jurisdictions.
- Discussions with management and operational personnel to understand the life characteristics of the assets and other relevant operating, technical and maintenance details that may impact the lives of the assets.

[Exhibit N-34, p. 59]

[236] As described by Mr. Madsen, when determining a visual fit to a specific Iowa curve, asset account retirement data is reviewed against an Iowa curve to assess how that data fits against the curve relative to alternatives. Visual fitting helps narrow curve types but must consider whether the underlying retirement data is limited or not representative of broader retirement data. Mr. Madsen stated that this is why mathematical curve fitting is also important. Mathematical fitting measures differences between observed retirement data points and the selected Iowa curve to help determine a best fit curve.

[237] Mr. Madsen also stated that peer analysis and comparison is especially important for NS Power, because its data relies heavily on simulated plant data, while peer utilities typically provide actual aged data across similar assets, allowing for a broader and more reliable comparison. As such, he opined that mathematical curve fitting for NS Power should be given less weight, since its reported simulated retirement data

may not reflect true historical patterns, especially where proposed asset lives differ significantly from peers. Finally, Mr. Madsen noted that discussions with company management and operational staff are essential to understand asset life characteristics and to assess whether historical retirement patterns are likely to change in the future.

[238] Mr. Madsen completed a review of Gannett Fleming's recommended asset average service lives for each of NS Power's Plant accounts. For transmission, distribution and general Plant accounts, Mr. Madsen generally followed the process described above. While he did not conduct discussions with NS Power personnel, he did review notes of discussions between company management and Gannett Fleming to help inform his analysis.

[239] Mr. Madsen's peer analysis compared NS Power's proposed average asset service lives to those of the peers used in Gannett Fleming's depreciation study. He also provided a second peer analysis by comparing NS Power's proposed average asset service lives to those noted in recent depreciation studies for NB Power, Maritime Electric (Prince Edward Island), and Newfoundland Power. Except for five Plant accounts, Mr. Madsen's analysis shows that NS Power has applied for average service lives lower than the Gannett Fleming peer average. Similarly, his analysis shows NS Power's proposed average service lives are generally lower than those used in New Brunswick, Prince Edward Island and Newfoundland. Mr. Madsen noted that when lower lives are considered alongside the ELG procedure, the combined result is more aggressive depreciation estimates and lives than are utilized by NS Power's peers.

[240] Based on his curve fitting, peer analysis and management notes review, Mr. Madsen recommended adjustments to the average asset service life and lowa curve for

several NS Power transmission and distribution Plant accounts. These recommendations are summarized in Table 8 of Mr. Madsen’s evidence as follows:

Account Number	Account Name	Investment at Dec 31, 2023	Emrydia Recommended Life Estimate	Emrydia Recommended Curve Estimate
TRANSMISSION ASSETS				
353	STATION EQUIPMENT	586,908,962	50	R2.5
354	TOWERS AND FIXTURES	111,028,870	No Change	No Change
355	POLES AND FIXTURES	268,176,042	50	R2.5
356	OVERHEAD CONDUCTORS AND DEVICES	178,454,463	52	R3
DISTRIBUTION ASSETS				
364	POLES, TOWERS AND FIXTURES	646,990,061	45	R1.5
365	OVERHEAD CONDUCTORS AND DEVICES	329,509,672	45	R2
367	UNDERGROUND CONDUCTORS AND DEVICES	75,012,364	No Change	No Change
368	LINE TRANSFORMERS	555,455,934	36	R1
GENERAL PLANT ASSETS				
390.1	STRUCTURES AND IMPROVEMENTS	184,609,960	No Change	No Change

[Exhibit N-34, p. 73]

[241] For NS Power’s production Plant accounts, Mr. Madsen conducted a slightly different review process, as NS Power’s IRP served as the formative document related to production Plant service lives. For this review, Mr. Madsen reviewed the detailed assumptions and lowa curves proposed by Gannett Fleming, reviewed the IRP and related materials to confirm the life span dates align with the most recent planning information, and reviewed the information obtained by Gannett Fleming from management to support its decisions.

[242] Based on his review, Mr. Madsen did have some concerns about the proposed retirement dates for some of NS Power’s production Plant. Nevertheless, he did not recommend any changes to the proposed service lives. In reaching this conclusion, he was mindful of the other depreciation related changes he recommended. He also noted the risks associated with NS Power’s forward-looking generation forecast, including the use of small modular reactors, significant reliance on wind and batteries, and other considerations. As such, he suggested that a wait and see approach through

to the next depreciation study and the next IRP would be a more pragmatic approach to addressing production Plant service lives.

3.4.3.1 Findings

[243] In Undertaking U-8, NS Power provided calculations showing the dollar effect of implementing the changes recommended in Table 8 of Mr. Madsen's evidence. NS Power performed the analysis using both the ALG and ELG depreciation procedures. The ALG calculations show a reduction in depreciation expenses (as compared to NS Power's GRA filing) of \$25.7 million and \$27.3 million in 2026 and 2027, respectively. The ELG calculations show a reduction of \$6.1 million in 2026 and \$6.5 million in 2027.

[244] The ALG calculations show a significant decrease in depreciation expense if Mr. Madsen's average service life recommendations are approved in combination with NS Power switching to the ALG depreciation procedure. These reductions would result in lower average rate increases for NS Power customers over the 2026 and 2027 test period (although they would be offset partially by the related increase in return on rate base). However, the ALG calculations are moot at this point, given the Board's findings elsewhere in this decision that it will not require NS Power to switch to ALG for the 2026/2027 test period.

[245] The ELG calculations also show a decrease in depreciation expense if Mr. Madsen's average service life recommendations are approved. These reductions too would result in lower average rate increases for NS Power customers over the 2026 and 2027 test period (although they would also be offset partially by the related increase in return on rate base). The issue for the Board to decide is whether Mr. Madsen's recommendations are warranted.

[246] During the hearing, Mr. Wiedmayer was questioned about the average service life changes recommended by Mr. Madsen:

MEMBER MURPHY: This is my last question. It's related to asset service lives and retirement dates. And in Mr. Madsen's evidence he referenced a number of your curves, I suppose, and how they fit with the data, the actual retirement data. And there was one in particular where it was related to transmission poles and fixtures, and Mr. Madsen had recommended a 50-R2.5 curve, and you have a 45-R1.5. And when you look at the curve -- I could call it up. When you look at the curve Mr. Madsen suggests that beyond year 30.5 the data doesn't fit very well, and that's part of the reason I think why he's suggesting a different curve. I can call the curve up if you want. But it does look like ---

A. (Wiedmayer) Yes, I would like to see that, because that is a good example of one that I think we should look at.

Q. Okay. It's -- Jeff, it's Exhibit N-34, PDF page 83.

MEMBER MURPHY: And Mr. Madsen made the same comment, Mr. Wiedmayer, this particular curve is just for transmission poles and fixtures, but he also made similar comments related to some of the other asset groups where the curves that you suggested don't fit that well.

In this particular case when I look at the curve it does look to me that it's not a great fit after year 30 or so. So my question was, you know, in this particular case, why do you think that 45-R1.5 is better than the one that Mr. Madsen suggested?

A. (Wiedmayer) Okay. Yeah, so here's a really good example, in the sense that the historical data is represented by those squares, black squares on the chart. So Nova Scotia's historical retirement experience indicates, when I look at this chart -- I know not everybody in the room is a depreciation expert, but what it indicates to me that the 45-year average service life indicated by that smooth black line is above or to the right of the black squares. So really the best fit IOWA types or R curve for this account probably is more like a 41- or a 42-year average service life from a historical basis.

So I had in the previous study recommended a 47-year average service life. However, Nova Scotia with, I think, tropical storms becoming more and more prevalent and some other reasons for earlier retirements, your actual retirement experience is indicating shorter lives than what I have proposed. Mr. Madsen's 50-year average service life would be even further above and to the right of my 45-R-1.5. So Mr. Madsen's 50-year recommendation is based, I would suspect, purely on industry data and judgment and not based on the company's actual retirement experience, which is a shorter life -- an even shorter life than what I've recommended.

Q. So in your opinion I guess, from what I'm hearing, the curves that are recommended by -- in this particular case anyway, the curve recommended by Mr. Madsen would be even a worse fit to that actual data; correct?

A. (Wiedmayer) Correct. That's exactly correct, yes.

[Transcript, January 7, 2026, pp. 323-326]

[247] Mr. Madsen responded to the points raised in this exchange during his own hearing testimony:

BY MEMBER MURPHY: ...this is the curve that I walked through with Mr. Wiedmayer the other day, and this is for account 355. And Nova Scotia Power is recommending using the Iowa 45-R1.5 curve, and I think you were recommending the — I think it was the R50.

...

A. (Madsen) Fifty (50)-R2.5.

Q. That's right, yeah. And when I asked Mr. Wiedmayer about this, he indicated that [if] the Iowa 50-R2.5 curve was used here, it would be further to the right than the curve you suggested, or the curve that Nova Scotia Power suggested, and that would seem to indicate that the curve you recommended is a worse fit to that, I guess, simulated data, those squares, than Gannett Fleming had recommended. I'm just wondering if you have any comment on that.

A. (Madsen) Yes. So he is correct. The curve that I recommend would have a worse fit to the retirement data. Again, this is simulated retirement data. And it would not represent the actual retirement data that would be present for Nova Scotia Power had it had that historical information.

I think if it's — it may not be helpful, but if you look at some of the other reports, Mr. Murphy, that I filed, for example Newfoundland Power, and the similar data for this account where there is actual aged data, not simulated age data, you see that there is a very different trend in the aged data relative to what is shown here on a simulated basis.

And that is why when I recommended the curve that I did, I recommended a curve with a longer life, which does not fit this aged data as well, because I can't devise a reason why Nova Scotia Power would have retirements for account 355, which is poles and fixtures, which would suggest a life of 40 to 41 years, and I think that's what Mr. Wiedmayer confirmed as well. And when I modelled it, I figure — I noted that best-fit curve would be similar along a 41-R1 curve to that data.

A 41-year life for this account would be well below the range of peers, well below what I have seen in other jurisdictions. And if I were to simply rely on the simulated data, again keeping my simulated data, and run a conclusion, the conclusion that that is the best curve to select, then I think that would result in a recommendation that is incorrect, and that's why I did not recommend it.

Q. Okay. The other curves you recommended for the other accounts, if I look at them all in general, they would all tend to fall to the right of the curves that Gannett Fleming had recommended. So I guess if I was to ask you the same question about all those other accounts I would get the same answer; correct?

A. (Madsen) Same answer, sir. Maybe it would be helpful if we had before us actual retirement data, and I describe this in my report. If this curve that we were looking at was actual retirement data, I'd probably be asking myself why Gannett Fleming did not recommend a 41-R1 curve, and I would probably start with recommending a 41-R1 curve because that would best reflect the actual retirement data for Nova Scotia Power. We're not looking at actual retirement data, which is why I need to assign the weight to the simulated data that I can, and in my opinion, I would not assign significant weight.

Now again, if the simulated data was showing that — the best guess was showing that for this account Nova Scotia Power was dead set right in the middle of its — the recommended peer range, say somewhere around 50 years, and management's notes suggested that that was consistent with their expectations of the life of the asset, I would likely be again recommending that the simulated data provided more weight because it is consistent with the other data that I have reviewed. In this case, it's just so inconsistent it's hard to assign significant weight to it. [Emphasis added]

[Transcript, January 12, 2026, pp. 1153-1157]

[248] There are two primary arguments that Mr. Madsen is making for his recommended changes to NS Power's average asset service lives. First, he argues that NS Power's use of simulated aged data would not represent actual NS Power retirement data if the company had that historical information. And second, he asserts that the average service lives put forward by NS Power are materially lower and inexplicably different than its peer utilities, particularly other Atlantic Canadian utilities.

[249] Throughout his hearing testimony, Mr. Wiedmayer discussed his use of peer utility comparisons as more of a reasonableness check. He uses such comparisons to make sure his estimates for average asset service lives are within the bounds used by other utilities. He noted, however, that he does not use these comparisons as a substitute for a company's actual historical asset retirement experience. If a reasonableness check shows significant differences between his recommended service lives and the bounds of other peer utilities, he would then review the material once again with utility staff to determine the reasons why and if adjustments are required. He also noted that each electric utility has its own unique survivor characteristics due to a variety of reasons, including differences in capitalization policies, differences in maintenance practices, and differences in the type of structures that are in specific asset accounts.

[250] During hearing questioning from Board Counsel, Mr. Wiedmayer also took issue with Mr. Madsen's argument about NS Power's use of simulated aged data. Mr.

Wiedmayer pointed out that he did, in fact, use actual data for NS Power, but that the retirements were not aged. Specifically, he used actual data about when assets were installed but did not know when the related retirements occurred. Then, based on the addition and retirement pattern, simulation was used to place a reasonable age on the retirements that did occur.

[251] In general, the Board agrees with NS Power in its closing submissions that calculation of depreciation rates requires professional judgement and experts can have differing opinions on the appropriate survivor curves and service lives. The Board also finds that Mr. Wiedmayer's arguments about the use of simulated data and checks against peer utilities are reasonable. However, the Board finds Mr. Madsen's evidence to be more compelling, particularly as it relates to many of NS Power's average asset service lives being much lower than those of its Atlantic Canadian peer utilities. Therefore, for the purposes of the current GRA, the Board finds that the average asset services lives recommended by Mr. Madsen for the accounts noted in Table 8 of Mr. Madsen's evidence are more reasonable than those put forward by NS Power. Nonetheless, for the reasons that follow, the Board will not direct NS Power to make the related changes to its GRA.

[252] The average service life changes recommended by Mr. Madsen would result in slightly lower average rate increases for NS Power ratepayers over the 2026/2027 test period. However, the reduction in related depreciation expense must also be considered in the context of the status of NS Power's intended securitization of assets within the scope of the DDA. With securitization remaining uncertain, as explained later in this decision, a change in NS Power's proposed depreciation expense from what is proposed in the application would affect its FFO:Debt credit metrics even further. This

could increase the risk of having the credit rating agencies lower NS Power's credit rating to "junk" status. As noted in Morrison Park's evidence, this would have serious long-term cost consequences resulting in higher costs for ratepayers.

[253] Therefore, the Board accepts the average asset services lives as presented by NS Power in the settlement agreement. As such, for the purposes of the current GRA, the Board will not direct NS Power to adjust the average service lives of the accounts recommended by Mr. Madsen.

[254] This notwithstanding, Mr. Madsen made some other recommendations related to those accounts. These recommendations include:

- Account 354 – Towers and Fixtures: NS Power should track the nature of additions to this account going forward, and to the extent practicable, break out the historical cost of new towers within the account. This information should be provided as part of NS Power's next depreciation study.
- Account 356 – Overhead Conductors and Devices: NS Power should better study the physical lives of the assets in this account and describe in detail the types of assets installed by type, quantity, and estimated age. NS Power should also segregate its overhead conductor in Account 356 into the conductor that is strung on higher dollar value steel towers with longer lives and provide NS Power's estimate of the service lives of that conductor with explanations. This information should be provided as part of NS Power's next depreciation study.
- Account 367 – Underground Conductors and Devices: In its next depreciation study, NS Power should explain the proposed life and why that life is appropriate considering NS Power's facts and circumstances.

- Account 390.10 – Structures and Improvements: For each major structure in this account, NS Power should disclose the expected useful lives of the assets, the date the asset was acquired or constructed, and identify when NS Power expects to retire each asset. This data will provide further information to better understand the likely average service life of these assets. This information should be provided as part of NS Power’s next depreciation study.

The Board believes that these recommendations would be useful moving forward. Therefore, the Board directs NS Power to address each of these recommendations in its next depreciation study filed with the Board.

[255] Mr. Madsen also recommended that the Board direct NS Power to provide at minimum the following information in support of both production Plant and mass property as part of its next depreciation study, rather than wait for that information to be requested through the information request process:

- Detailed management notes for each account;
- All analysis and studies performed by management for each asset to confirm the expected life;
- All updated IRP documents;
- A reconciliation of the lives proposed in the depreciation study to the lives proposed in the IRP; and
- The peer analysis relied upon by the company in an Excel file.

The Board agrees with Mr. Madsen’s recommendations. Further, during the hearing, NS Power witnesses agreed that providing this information would be reasonable. Therefore,

the Board directs NS Power to include this information in its next depreciation study filed with the Board.

3.4.4 Amortization Accounting for General Plant Assets

[256] NS Power has proposed the use of amortization accounting for certain General Plant accounts that represent numerous units of property, but a very small portion of depreciable electric 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.

[257] 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.

[258] The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in the NS Power depreciation study are based on Gannett Fleming'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.

[259] NS Power has proposed the use of amortization accounting for the following General Plant accounts:

- Account 391.10 Furniture and Equipment (20-year amortization period),

- Account 391.31 Computer Equipment – Hardware (5-year amortization period),
- Account 391.32 Computer Software (10-year amortization period),
- Account 394.00 Shop Equipment (20-year amortization period), and
- Account 398.00 Miscellaneous Equipment (20-year amortization period).

[260] In response to NSEB IR-83, NS Power stated that many electric utilities in North America have received regulatory approval to adopt amortization accounting for these groups within general plant. Examples include Newfoundland Power, BC Hydro, Centra Gas Alberta Inc., UGI Utilities Inc. – Electric Division, and West Penn Power Co. The United States Federal Energy Regulatory Commission (FERC) through its Accounting Release 15 has also accepted the use of amortization accounting for these groups. Mr. Madsen also noted that the use of amortization accounting for such accounts is common for utilities.

[261] Amortization accounting for these General Plant accounts would require NS Power to retire vintaged asset balances that are assumed to be fully depreciated as determined in the depreciation study. The lower depreciation as a result of these retirements would be offset by a reserve imbalance amortization charge. A reserve imbalance is caused by Plant and reserve activity that is different than what depreciation models forecasted. It is calculated as the difference between the book reserve and the theoretical reserve for an asset. The theoretical reserve is the amount that should have been collected based on the age of the asset and the selected amortization related to these five General Plant accounts. The theoretical reserve is used as a benchmark to assess the adequacy of the NS Power's book reserve. Any difference between the two is trued up prospectively over a reasonable amortization period. Per Gannett Fleming's

recommendation, NS Power intends to amortize the reserve imbalance over a 5-year period using whole life amortization rates.

3.4.4.1 Findings

[262] In its GRA, NS Power stated that the estimated impact of adopting amortization accounting would result in annual incremental depreciation expense of \$600,000 over the test years. This is primarily related to the implementation of shorter amortization periods for some assets.

[263] The Board notes that the asset groups NS Power 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 will result in lower administrative overhead costs without any material reduction in accounting accuracy. As such, the Board agrees with NS Power that the proposed amortization accounting for these accounts is a cost-effective way to manage cost recovery.

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

3.4.5 Submissions of the Nova Scotia Department of Energy

[265] The Department of Energy presented the following on page 6 its closing submissions:

30. The copy of the Gannet Fleming depreciation study as of December 31, 2023, does not contain any reference to the words “stranded,” “useful life,” “government” or “legislation,” which suggests that none of these factors were considered in determining appropriate depreciation. In fact, the following is an excerpt from a summary of the year in service, probable retirement year and life span for each power production facility taken from the Report:

A summary of the year in service, probable retirement year and life span for each power production facility follows:

<u>Depreciable Group</u>	<u>Nameplate Capacity Rating, MW</u>	<u>Year in Service</u>	<u>Probable Retirement Year</u>	<u>Life Span</u>
<u>Steam Production Plant</u>				
Lingan Units 1	150.5	1980	2049	69
Lingan Units 2	150.5	1981	2029	48
Lingan Units 3-4	150.5	1984	2049	65
Point Aconi	165.0	1994	2029	35
Point Tupper	150.0	1973	2048	75
Trenton 5	150.0	1970	2029	59
Trenton 6	160.0	1992	2029	37
Tufts Cove 1	100.0	1966	2049	83
Tufts Cove 2	100.0	1973	2049	76
Tufts Cove 3	150.0	1977	2049	72
Tufts Cove 6	50.0	2011	2049	38

31. The Department asks that the Board review the “Probable Retirement Year” column whilst considering existing legislation and government policy.

[266] The Board has reviewed the “Probable Retirement Year” column and finds it is acceptable and consistent with retirement dates noted in the company’s most recent 10-Year System Outlook Report. In particular, Lingan 1, 3 and 4 are currently scheduled to be converted from coal-fired to heavy fuel oil fired in 2029. Similarly, Point Tupper is scheduled to be converted from coal-fired to natural gas-fired in 2029. As such, these facilities will meet existing legislation mandating that NS Power be off coal by 2030.

[267] The Department of Energy also submitted that NS Power’s failure to diligently file updated depreciation studies may have resulted in excessive returns to the utility. The Department of Energy contends that had NS Power prepared timely, updated depreciation studies, NS Power’s overall allowable returns would likely have been reduced, resulting in lower rates for ratepayers. The Board notes that the Department of Energy’s contention would only be true if the updated depreciation studies resulted in higher depreciation rates. Further, if that was the case, this does not necessarily mean that lower overall rates would result for ratepayers. As explained previously in this

decision, higher depreciation rates result in higher rates for ratepayers which are offset by some degree by lower return on rate base.

3.4.6 Depreciation – Summary

[268] For the purposes of the current GRA, the Board finds it appropriate to exclude decommissioning costs for the Wreck Cove, Mersey, and Tusket hydro systems from proposed depreciation rates for the 2026 and 2027 test years. The Board directs NS Power to provide, in its next depreciation study, a reconciliation (from 2009 onward) of annual interim and final net salvage collections and actual salvage costs for these hydro assets.

[269] For the purposes of the current GRA, the Board accepts the inclusion of partial decommissioning costs of NS Power's other hydro Plant assets in depreciation rates for the test years. Nonetheless, the Board agrees with NS Power that no settled policy or multi-stakeholder framework currently exists to determine whether, when, or how partial or full decommissioning costs for hydro Plant should be included in depreciation rates. Similarly, no such policy or framework currently exists to identify who should bear on-going costs associated with partially decommissioned hydro assets that are no longer used and useful. As such, the Board directs NS Power to initiate a structured engagement process involving regulators, government, and other relevant parties to address this issue, with an ideal target completion in advance of NS Power's next GRA. During this process, the Board directs NS Power to file regular update reports with the Board once every six months, beginning October 1, 2026.

[270] The Board finds that the majority of the proposed net salvage rates in the settlement agreement fall within a reasonable range. The Board, therefore, approves the net salvage rates for Plant accounts not subject to settlement agreement adjustments

and for the three transmission and distribution Plant accounts which are subject to settlement agreement adjustments.

[271] The Board has intergenerational equity concerns though with the settlement agreement adjustments affecting production Plant net salvage rates, which recovers the expected future costs to salvage and remove/decommission these assets, including any salvage proceeds. Generally, the Board would be inclined to not approve these adjustments even though this would result in a slight increase in average customer rates in the current GRA. However, at this point there remains considerable uncertainty related to current decommissioning cost estimates for these assets. This is particularly true for NS Power's hydro assets, where it remains uncertain whether these assets will eventually undergo partial or full decommissioning, or even be decommissioned at all. As noted above, the Board has directed NS Power to address this issue before its next GRA. Given this uncertainty, the potential impact, if any, of assumed production Plant net salvage rates on future ratepayers is unclear. In this circumstance, the Board accepts the proposed settlement agreement adjustments to net salvage rates for NS Power's production plant accounts. Therefore, for the purposes of the current GRA, the Board also approves the settlement agreement adjustments to net salvage rates for NS Power's production plant accounts.

[272] The Board also finds that the use of the ALG depreciation procedure likely represents a more reasonable, equitable and prudent depreciation framework than continued use of ELG by NS Power. The Board further finds that the average asset services lives recommended by Mr. Madsen for the accounts noted in Table 8 of his evidence are more reasonable than those put forward by NS Power. Generally, the Board

would be inclined to direct these changes, which would result in a decrease in average customer rates in the current GRA.

[273] If the Board were to direct NS Power to change to the ALG depreciation procedure and to adopt the asset service life changes recommended by Mr. Madsen, NS Power's depreciation rates in the GRA test period would be reduced by roughly \$45 million. This would equate to a one-time pre-tax decrease in average customer rates of approximately 2%. However, downward adjustments to NS Power's depreciation expense included in revenue requirement would have the effect of decreasing the company's cash flow. It would also reduce recovery of capital investment thereby increasing debt. These factors would negatively impact NS Power's FFO:Debt credit metrics.

[274] In Undertaking U-7, NS Power provided estimates of forecast FFO:Debt credit metrics under both the ALG and ELG depreciation procedures with and without the settlement agreement adjustments, and under the assumption that securitization of the assets within the scope of the DDA proceeds. These estimates show that under the ELG methodology with the settlement agreement adjustments, the FFO:Debt metric will be 12.1% to 12.3% in 2026 and 12.7% to 12.8% in 2027. Under ALG with the settlement agreement adjustments, the metric estimates range from 10.9% to 11.1% in 2026 and 11.4% to 11.5% in 2027. So, if the Board were to direct NS Power to use the ALG procedure, NS Power's FFO:Debt credit metric would be reduced by roughly 1.2%. Again, this is under the assumption that securitization of the assets within the scope of the DDA proceeds.

[275] In response to NSEB IR-122, NS Power indicated that if its GRA application is approved by the Board and if securitization of the assets within the scope of the DDA does not proceed, its FFO:Debt credit metric would be 10.7% in 2026 and 11.1% to 11.2% in 2027. Therefore, if the Board directs NS Power to use the ALG depreciation procedure, and securitization of the assets within the scope of the DDA does not proceed, the company's credit metric would fall below 10% in both 2026 and 2027. If the Board were to further direct NS Power to make the asset service life adjustments recommended by Mr. Madsen, these metrics would degrade further but only nominally.

[276] As Pelino Colaiacovo of Morrison Park noted in his testimony, credit metrics at this level would be problematic. This could increase the risk of having the credit rating agencies lower NS Power's credit rating to "junk" status. As noted in Morrison Park's evidence, this would have serious long-term cost consequences resulting in higher costs for ratepayers.

[277] The service life and ALG changes the Board has considered would result in lower rates for customers over the test period. Nevertheless, in the Board's opinion, the increased credit rating risk related to these changes coupled with the uncertainty of securitization of the assets within the scope of the DDA not proceeding (as indicated in the Department of Energy's closing submissions), would more than offset the benefit of the depreciation related changes considered by the Board. As noted by Morrison Park:

A downgrade of NSPI's credit rating would have serious long-term consequences, as the company would no longer be investment grade. All new issuances of debt would be significantly more expensive than was historically the case. Immediate consequences would likely include lack of access to the commercial paper market, and the breaching of covenants in project agreements with partners like the CIB. These consequences go beyond the monetary in nature.

[Exhibit N-36, p. 26]

[278] Therefore, for the purposes of the current GRA, the Board will not direct NS Power to use the ALG depreciation procedure for the current GRA. This notwithstanding, the Board directs NS Power to file an updated depreciation study with its next general rate application. The Board expects that this depreciation study will address, but not be limited to, the following issues:

- Depreciation expense and rate base interaction;
- Extent of true aged data use;
- A NS Power specific ALG vs. ELG crossover analysis;
- Peer utility comparisons;
- Analysis of forces of retirement unique to Nova Scotia;
- Accumulated depreciation reserve deficiency impacts under both methods;
- Whether a phased-in transition to ALG would be appropriate; and
- Proposed depreciation rates by asset accounts under both ELG and ALG procedures.

[279] Moreover, for the purposes of the current GRA, the Board approves the asset service lives presented in NS Power's application, including the settlement agreement adjustments made to service lives for Accounts 353 and 390.10. The Board directs NS Power to address Mr. Madsen's recommendations related to asset Accounts 354, 356, 367 and 390.10 in its next depreciation study filed with the Board, NS Power is also directed to provide the following information in its next depreciation study filed with the Board:

- Detailed management notes for each account;
- All analysis and studies performed by management for each asset to confirm the expected life;
- All updated IRP documents;

- A reconciliation of the lives proposed in the depreciation study to the lives proposed in the IRP; and
- The peer analysis relied upon by the company in an Excel file.

[280] The Board approves the use of amortization accounting for the following five General Plant accounts:

- Account 391.10 Furniture and Equipment (20-year amortization period);
- Account 391.31 Computer Equipment – Hardware (5-year amortization period);
- Account 391.32 Computer Software (10-year amortization period);
- Account 394.00 Shop Equipment (20-year amortization period); and
- Account 398.00 Miscellaneous Equipment (20-year amortization period).

3.5 Regulatory Deferrals

3.5.1 Securitization Deferral

3.5.1.1 Background

[281] Securitization was described by NS Power as the “centrepiece” of its general rate application and the settlement agreement. The practical impact of securitization in this matter is that it would result in ratepayers paying a lower financing rate on retiring certain utility coal plant and related assets as required under federal and provincial decarbonization policies. In its application, NS Power estimated that securitization could save customers about \$90 million over the 2026 and 2027 period.

[282] Securitization is a complex commercial transaction which removes assets from a utility’s balance sheet and restructures the assets into debt, which is then refinanced in a bond issuance or other type of securities offered to investors in the debt markets. The purpose of securitization is to obtain the highest possible credit rating so

that the bond issuance can attract a materially lower interest rate than the return on rate base otherwise paid to the utility by ratepayers on those assets. Since the utility should be able to reduce the financing costs for the securitized assets, ratepayers will be able to pay lower financing costs over the term of the amortization period. After the securitization, the utility's shareholders no longer earn a return on the assets. Further, since the debt associated with the assets has been removed from the balance sheet, the securitization results in improved credit metrics for the utility.

[283] There are a few steps to implement a securitization. First, there must be legislation in effect authorizing a securitization process for the assets, including the issuance of a financing order by the regulator and the creation of a charge or pledge that will provide bondholders an irrevocable right to receive the bond principal and interest from ratepayers to retire the securitized debt. This is important so that the debt can attract the highest possible credit rating to obtain the lowest interest rates.

[284] Second, the regulator must issue a financing order authorizing the securitization to proceed on the identified assets. The financing order typically confirms the irrevocable nature of the charge to be paid by ratepayers. The order may also direct a true-up mechanism to adjust the charge to ensure the coverage of the principal and interest if energy sales vary from forecast. As noted in prior matters, complex commercial transactions involving the corporate structure of the utility may also be required to implement the securitization and isolate the securitized debt for the benefit of bondholders, usually through a special purpose entity. In the case of NS Power, this involves dealing with corporate items such as trust indenture and debt covenant-related

issues, together with the assessment of credit rating agency treatment and income tax treatment of the amounts to be securitized (see 2024 NSUARB 67, M11220, para. 105).

[285] NS Power intends to request approval of the securitization of \$704 million of the unrecovered net book value of thermal assets within the scope of the Decarbonization Deferral Account (\$500 million in 2025 and \$204 million in 2026). However, since legislation has yet to be enacted in Nova Scotia to authorize securitization, NS Power requested the Board's approval of a "securitization deferral" in the event securitization was delayed and could not be completed by January 1, 2026. For this deferral, the depreciation expense and financing costs of these assets intended to be securitized on January 1, 2026, would be deferred at WACC on an interim basis until securitization is in place. The intent is to add the deferred depreciation and financing costs to the amount to be securitized. The issue to be addressed in this application is whether this deferral account should be approved. NS Power will seek Board approval of the securitization in a subsequent application, should it proceed.

[286] Securitization by utilities is more prevalent in the United States. The present case may be the first example of this mechanism being proposed by an investor-owned regulated utility in Canada. A form of securitization was applied in Ontario a few years ago for Ontario Power Generation, a Crown-owned utility.

[287] A successful securitization should reduce costs for ratepayers. For example, instead of paying NS Power's weighted average cost of capital on a deferral account (which is currently set at 6.65% for 2025), ratepayers would potentially pay a lower interest rate on a bond issuance authorized under a financing order. NS Power estimated the interest rate that could be achieved in a bond issuance at about 5%, based

on market conditions forecast in November 2025 (see Morrison Park IR-7). The result of the above is that NS Power would no longer earn a return on the securitized assets.

[288] Securitization has been raised over the past several years in proceedings involving NS Power, with the Board and intervenors urging NS Power to investigate this option as a means to mitigate rate impacts on ratepayers. A similar mechanism was used to address a significant FAM balance owed by ratepayers, and more recently in matters leading to the present application about the costs associated with the retirement of coal plants. As noted by counsel for the Municipal Electric Utilities of Nova Scotia (MEUs), NS Power appeared reluctant to pursue securitization until recently:

It is worth noting that NS Power was initially opposed to securitization. In a May 3, 2022 response to questions in its 2022-2024 General Rate Application (“GRA”), NS Power stated: “...there are other factors which make securitization not the preferred approach for NS Power at this time.”

The Settlement Agreement in the 2022-2024 GRA included an agreement in principle to the DDA to recover undepreciated thermal asset NBV and unrecovered decommissioning costs. Although the Board’s decision in the 2022-2024 GRA identified several items to be addressed in the subsequent filing, including potential use of securitization, NS Power’s June 30, 2023 application for the DDA in Matter M11220 proposed deferring any investigation of securitization. Intervenors noted NS Power reiterated securitization was not its preferred mechanism and did not conduct any form of economic analysis to assess the cost or benefit of securitization compared to financing at NS Power’s Weighted Average Cost of Capital (“WACC”).

At para. 111 of its April 10, 2024 decision approving the DDA in that matter, the Board agreed that NS Power was non-responsive on the issue of securitization and endorsed the intervenor comments. The Board directed a meaningful investigation of the potential use of securitization with a report due no later than April 30, 2025.

[MEUs Closing Submission, January 30, 2026, p. 4]

[289] As is the case in other jurisdictions, securitization must be authorized by legislation before it can be implemented. In its final report in February 2024, the Nova Scotia Clean Electricity Solutions Task Force recommended that new legislative provisions allow the Board to have “a complete suite of tools to ensure lowest cost for utility customers in dealing with the financial consequences of the early retirement of

NSPI's coal fired facilities" (p. 46), referring to securitization, among other mechanisms. The Province accepted this recommendation and amended the *Public Utilities Act* in April 2024 to introduce a provision allowing the Board to issue a financing order authorizing a securitization: *Energy Reform (2024) Act*, SNS 2024, c 2, s 72:

35G (1) The Energy Board and the Regulatory Board may approve, deny or modify an application for a financing order.

(2) The Governor in Council may make regulations respecting all aspects of financing orders, including defining financing orders and when they may be used.

(3) The exercise by the Governor in Council of the authority contained in subsection (2) is a regulation within the meaning of the Regulations Act.

[290] However, to date, s. 35G has not been proclaimed and no regulations have been enacted to implement the securitization process.

3.5.1.2 Present Application

[291] In this application, NS Power indicated its future intent to ask for the securitization of \$704 million of the unrecovered net book value of thermal assets within the scope of the DDA (\$500 million in 2025 and \$204 million in 2026). At the time of its application in September 2025, it submitted that securitization would save ratepayers \$90 million in the 2026-2027 test period. Later, in response to an IR from Morrison Park in November 2025, NS Power updated its forecast and the savings at that time were estimated at about \$85 million over the 2026-2027 test period.

[292] However, the current application does not ask for Board approval of securitization. In its September 2025 general rate application, NS Power stated that if the securitization could not be completed by January 1, 2026, it requested the Board, in the interim, approve a "securitization deferral" to defer at WACC the depreciation expense and financing costs of the unrecovered net book value of the thermal plant assets within

the scope of the DDA, until securitization can move forward. The assets sought to be securitized would be the thermal assets related to Point Aconi, Trenton, the Point Tupper Marine Terminal, the Sydney International Coal Pier, and steam general assets. NS Power also proposes to add the deferred depreciation and financing costs accrued in the deferral account to the securitization amount. It said at the January 2026 hearing that the Province had not yet proclaimed the legislation to allow the securitization to proceed and confirmed its request for the securitization deferral.

[293] NS Power also noted in its application that it had to address some preliminary corporate items in advance of the securitization:

... No Canadian investor-owned utility has undertaken a securitization similar to those undertaken by United States investor-owned utilities. As such, it is anticipated that a NS Power securitization will require identifying a finance structure to resolve a variety of issues including, but not limited to, credit rating, trust indenture and tax considerations. Subject to successful credit rating agency processes and the issuance of enabling regulations, NS Power intends to apply to the NSEB for approval for the securitization of approximately \$700 million of DDA assets over the GRA period.

[Exhibit N-3, p. 52]

[294] The settlement agreement contemplated NS Power applying to the Board for the proposed securitization, stating that “NS Power will make best efforts to finalize and apply prior to January 1, 2026, for approval of its proposed securitization of assets, cost-of-service treatment and the Securitization Rider”. It was also agreed among the parties that they could take any position they choose about such an application. Given that the parties agreed to NS Power applying for the securitization and reiterated that support in their closing submissions, the Board infers that the customer representatives reserved the opportunity to comment on cost-of-service issues, the form or operation of the rate recovery rider, etc. However, the requested securitization deferral itself was not canvassed in the settlement agreement, as NS Power acknowledged to the Small

Business Advocate in cross-examination (Transcript, January 7, 2026, p. 209, lines 11-13).

[295] Morrison Park reviewed the general rate application in the context of the company's credit rating issues and the proposed securitization. With respect to the latter, Morrison Park confirmed that securitization would help the utility in improving its credit metrics. Specifically, Morrison Park stated that in the absence of both securitization and its requested rate increase, NS Power would be unable to meet its credit metrics thresholds and its credit rating would be seriously jeopardized. Morrison Park noted that NS Power had suffered a credit rating downgrade in November 2022 to BBB-, which is the lowest investment grade status and just one level above "junk bond" status. Morrison Park cautioned that the Board needs to be mindful of the risk of the utility dropping to "junk bond" status. It said a further downgrade would have "potentially significant consequences", noting the importance of NS Power maintaining a minimum target of 10% FFO:Debt, that being a key credit metric monitored by credit rating agencies.

[296] Morrison Park noted that matters impacting NS Power's credit ratings can result in higher borrowing costs. It described the circumstances which occurred in late 2022:

In November of 2022, NSPI's rating was downgraded by two notches by S&P, to BBB-, a rating which it continues to have today. As reported by NSPI in the application, this places NSPI in the bottom 10% of utilities in North America. The vast majority of utilities have credit ratings of BBB+ or higher.

In the November 21, 2022 Research Update in which S&P reported on the downgrade of NSPI's rating, the primary cause of the ratings action was described as the enactment by the province of Nova Scotia of Bill 212, which would override the authority of the then-NSUARB, and limit the increase in electricity rates by fiat. This was described by S&P as a "political intervention" in the independence of the regulator, and caused the downgrading of the business risk profile of the utility to "strong" from "excellent". Many other factors were addressed, but the overriding issue of government policy was clear. At the same time, because of the expectation that financial results at NSPI would deteriorate based on the legislation, S&P reduced its Financial Risk rating by one category to "aggressive". The combination of these two changes results, based on the table in Figure 2 above, in a

standalone credit rating of BB+, and the company would have lost its investment grade status. However, as a subsidiary of Emera, NSPI was accorded the benefit of a one notch advantage, and thus was reduced only to BBB-, instead of BB+.

As of S&P's most recent report, in January of 2025, the rating of BBB- was affirmed, and a specific mention was made relating to the financial risk metric FFO:Debt, such that "We could lower our ratings on NSPI over the next 12-24 months if: Financial measures deteriorated, with FFO to debt consistently below 10%, or We lowered our rating on parent Emera." It is perhaps worth emphasizing the term "consistently below 10%", in the quote above.

[Exhibit N-36, pp. 12-13]

[297] Morrison Park explained the consequences of a downgrade of NS Power's credit rating. It listed several circumstances that could lead to an additional \$25 million or more in costs per year for ratepayers [see Exhibit N-36, pp. 24-25]:

- NS Power is forecasting a \$250 million bond issuance in 2027. Based on Government of Canada 30-year bond rates at the time of Morrison Park's report, and recent yield spreads on the company's bonds, the consultant estimated the bond interest rate to be under 5%. If the utility suffered a downgrade, the interest rate it could achieve on the bond issuance would be at least 2% higher. The additional cost for ratepayers would be about \$5 million per year.
- Similar increases would apply to additional bond issuances, if there is a downgrade, noting it may take years to improve a credit rating following a downgrade. Morrison Park stated that NS Power will have to refinance about \$800 million of maturing bonds over the next 10 years, with similar increased interest costs to that described above.
- The same would apply to NS Power's debt financing for its Reliability Plan, which NS Power has forecast at \$1.3 billion over five years.
- As outlined in NS Power's response to Morrison Park IR-6, a downgrade from an investment grade rating could result in a default and penalties to the beneficial

financing arrangements received from the Government of Canada for recently approved large projects to support renewables on the grid and improve reliability. It could cause a 3% increase in the interest rate on NS Power's Battery Energy Storage Project and an increase in the return paid to the Canada Infrastructure Bank from 1.15% to 9.00% on the Wasoqonatl Transmission project for the NS/NB Reliability Intertie.

[298] However, Morrison Park also noted that bond markets do indeed react favourably to positive developments affecting NS Power, which it demonstrated in its report by examining the movement in yield spreads as between corporate bonds and government bonds in NS Power's instance relative to Hydro One in Ontario. It noted that bond markets appear to react more contemporaneously with positive developments than credit rating agencies. It referred to a few developments to address NS Power's FAM balance that occurred after the credit rating downgrade in late 2022, including the Government of Nova Scotia's purchase of \$117 million of FAM receivables in February 2024 and the Government of Canada providing its \$500 million Federal Loan Guarantee in late 2024 to address the remaining FAM balance. Morrison Park noted that NS Power's bond yield spreads decreased (i.e., improved) after these developments:

... the NSPI bond yields do decline from the January 2023 peak depicted in the charts, despite the fact that no improvements in credit ratings were announced throughout this period. [Emphasis in original] The various announcements about FAM arrangements with government no doubt contributed to the decline in NSPI yield spreads, as did the normalization of regulatory affairs, but in general that decline was gradual.

...

All of these observations suggest that the bond market reacts to events as they occur, and processes all available information, despite the lack of changes in credit ratings, or insights by credit rating agencies. It is also clear that the concrete steps to solve problems at NSPI – such as the securitization of the stranded FAM balances – was rewarded by the markets with lower yields on NSPI bonds. [Emphasis added]

[Exhibit N-36, p. 18]

[299] Morrison Park confirmed that securitization should reduce the business risk faced by NS Power, which could improve its credit metrics and its resulting credit rating. While it noted that a positive result in both the securitization and the proposed rate increases could provide more relief than what is required to ensure NS Power does not suffer a credit downgrade, the reverse is not true:

Given the magnitude of the impacts of each of the two initiatives separately, should NSPI's rate requests be rejected and its securitization plan not bear fruit, then it would be a certainty that the 10% FFO:Debt target would be missed in both [test] years.

[Exhibit N-36, p. 23]

[300] Further, as noted above, Morrison Park indicated that NS Power must refinance about \$800 million of long-term debt over the next 10 years. Morrison Park stated that interest rates are now historically low compared to the rates on existing 10, 20 or 30 year bonds coming due over the next few years. Thus, all else being equal, NS Power should be in a position to refinance maturing debt with lower cost debt. This would represent lower costs for this debt than what is currently embedded in rates.

[301] In his evidence, Mr. Madsen of Emrydia said he had no issues with NS Power's proposed securitization, but recommended the Board conduct a full review of the final securitization in a future process, including the recovery period of all costs. He noted that securitization is used to:

... allow for lower cost recovery of costs incurred by a utility that if included in base rates would cause rate shock or negatively impact the financial integrity of the utility.

The main benefit of securitization is that it provides for recovery of the costs based on low-cost debt financing, which is generally available as the cost recovery is either guaranteed or highly certain, and over a finite period of time. Absent denying recovery of the costs in rates, which has its own implications, securitization poses the lowest general cost to customers.

[Exhibit N-34, p. 117]

[302] Given Morrison Park's evidence that a downgrade to NS Power's credit rating could lead to an additional \$25 million or more in interest costs per year, it appears

that securitization, if allowed to proceed, could provide comfort about the utility's credit rating and potentially be a contributing factor to reduced costs for ratepayers over the long term. As noted above, bond markets have reacted favourably to positive developments impacting NS Power.

[303] NS Power had not applied for securitization as the end of 2025 approached.

On December 22, 2025, NS Power wrote to the Board requesting a securitization deferral pending the legislation being proclaimed and regulations enacted:

As stated in response to NSEB IR-89(a-c), while NS Power believes it will be able to proceed with a securitization application as soon as enabling regulations are in place, it now anticipates that securitization will be in place, at the earliest, by the end of Q1 2026. As such, and consistent with the stated intent set out in the GRA, NS Power is requesting Board approval to defer the depreciation expense and financing costs of the subject assets at WACC on an interim basis until such time as securitization is in place. As confirmed in response to NSEB IR-89(d), NS Power is proposing to add the deferred costs to the balance being securitized. NS Power anticipates that any assessment of the amount of deferred costs to be added to the securitized balance would be assessed by the Board as part of the application to approve securitization.

NS Power has discussed this request with customer representatives, but they have not provided their confirmed positions on the matter.

[304] NS Power was unable to report any progress on this issue at the hearing in January 2026. It confirmed in questioning from the Board that it had not received the intervenors' views about the proposed deferral, subject to what position they would take at the hearing. Further, at the hearing, the utility's estimated timeline for completion of the securitization was extended to Q2 2026, possibly Q3 2026, depending on the enactment of the regulations. However, the NS Power panel testified that it continued to engage with the provincial government to pursue this process:

Q. And I know there's been discussion through the Application other documents with respect to NSPI kind of waiting for the Regulations with respect to the securitization. What is the current status of the Regulations?

A. (Williams) The Regulations are with government, effectively. So Regulations obviously need to be put into effect from the provincial government, and so we're waiting for that to occur.

Q. Do you have any idea of how long that might take?

A. (Williams) I don't have any specifics on that, and that's why I was kind of trying to give a general timeline in terms of front half of this year to make the application, have it determined and have securitization in place.

Nova Scotia Power certainly has made efforts and will continue to make all efforts to ensure that as soon as we're able to move forward with that application we would do so without any delay.

Q. And just to be clear, do the Regulations have to be in place and enacted prior to your making the application?

A. (Williams) Yes, I believe so. The relevant provision of the PUA, which would also need to be enacted and would -- is very broad and very general and just provides for the issuance of Regulations, and the Regulations would provide the basis for that application.

[Transcript, January 7, 2026, pp. 210-212]

[305] In questioning by PHP counsel, NS Power confirmed that a six-month delay in proceeding with the securitization (i.e., by July 1, 2026, instead of January 1, 2026), would reduce the savings for NS Power and ratepayers realized over the two-year test period by one quarter (i.e., \$22.5 million in reduced savings).

[306] NS Power also confirmed that it had completed its preliminary steps to proceed with the securitization once the regulations are enacted by the Province. It stated that once s. 35G is proclaimed, the regulations are enacted, and the Board issues its financing order, the securitization could be completed in short order, on a timeline similar to what had transpired in the FLG2 debt issuance process conducted in December 2024 to refund \$500 million of the FAM balance to ratepayers (Transcript, January 9, 2026, pp. 904-905).

[307] At the very close of the hearing on January 13, 2026, NS Power indicated it had received information that could impact the timing of the securitization. The company indicated it would write to the Board immediately following the hearing to report on these

new facts, based on a message agreed to by the interveners present who had signed the settlement agreement. On January 14, 2026, NS Power wrote as follows:

In order to ensure the public record of matter M12451 is as complete as possible, NS Power writes to confirm that, as communicated during the confidential portion of the M12451 hearing on January 13, 2026, the exact timeline of securitization remains uncertain, but that NS Power continues to believe in its eventuality and that it is in the best interests of customers. [Emphasis added]

[Exhibit N-65]

[308] In closing submissions, the Department of Energy indicated that the Province is not currently inclined to allow the securitization to proceed due to concerns about the value of coal plant assets that would be securitized, submitting that this amount should be reduced (as canvassed elsewhere in this decision). The Province described its position as follows:

92. For initiatives that demonstrably protect ratepayers, the Department is all in. However, there remains considerable uncertainty regarding the appropriate value of coal assets that would form the basis of any securitization initiative. Without a clear and comprehensive understanding of these assets' appropriate value, it would be irresponsible to lock in a price that commits ratepayers to funding them into the future and for the Province to be financially exposed to risk through NS Power's request for the province to backstop the securitization loan.

...

94. The Province will not implement regulations creating a situation, securitization or otherwise, that could result in financial harm to ratepayers or fail to demonstrate clear ratepayer benefits. It could be that under certain circumstances some form of securitization makes sense. This conclusion has not been reached with respect to NS Power's proposition and as such the Province does not accept it. Until it is proven to save ratepayers money, it is a nonstarter.

95. The Department has worked with NS Power to try to develop an approach that would benefit ratepayers but to date has been unable to do so.

96. To this end, the Department also has significant concerns with assumptions NS Power made about the Province's position with respect to securitization. Specifically, the Consensus Agreement seems to suggest that NS Power and consumer representatives shared an understanding that securitization of Decarbonization Deferral Account liabilities was imminent. In fact, there has never been any firm commitment from the Province that it will change regulations to permit securitization.

[Department of Energy Closing Submissions, p. 15]

[309] However, in their closing submissions, NS Power and the customer representatives continued to support securitization and highlighted the savings that would accrue to ratepayers from the securitization. NS Power noted that the Province had taken initial steps to provide a process for securitization through the enactment of s. 35G of the *Public Utilities Act* and had outlined its support of this process in a letter to the utility dated May 6, 2025, from Karen M. Gatien, Deputy Minister of Energy, who stated:

In order to reduce electricity costs for Nova Scotians, I am writing to confirm that the Department of Energy is committed to continuing its engagement with Nova Scotia Power and other relevant stakeholders to develop an approach that would allow for the Nova Scotia Energy Board to issue a financing order. A financing order is used in section 35G of the *Public Utilities Act*, in order to facilitate the securitization of electric utility costs.

Any such approach would not come at a cost to the Government of Nova Scotia. It is my hope that this work can be successfully completed within the year.

[Exhibit N-7, Appendix 8F, PDF p. 650]

[310] Further, NS Power noted that the DDA approved during the 2023-2024 GRA proceeding (M10431) was identified as an initial step in the treatment of retired thermal assets, including as a preliminary step to securitization. It stated the “purpose of the DDA was to avoid the need to accelerate the recovery of the remaining costs of the coal assets and the resulting substantial increase in rates that would occur if a conventional depreciation study update was undertaken”. Christine Runge, of Power Advisory LLC, a consulting firm engaged by the Province in that matter, recognized that the DDA could potentially be the best option for recovery of costs associated with the early retirement of thermal generation assets. Nevertheless, she stated that it should not be approved unless more information is provided before assets are transferred to the DDA, including proposed amortization periods and rate impacts (see *NS Power 2023-2024 GRA Decision*, pp. 113-114). The Board sees this as consistent with a process that would

ultimately implement securitization, which would have to come to the Board in a separate process for approval.

[311] In the interim, most of the customer representatives supported the securitization deferral but did not agree with NS Power that the deferral should be made effective retroactive to January 1, 2026. In their view, the securitization deferral should only take effect when new rates are implemented. Otherwise, these intervenors argued that this would amount to double recovery because, as the Small Business Advocate submitted, depreciation expense and financing costs for these assets are already embedded in NS Power's existing rates. The MEUs stated that the deferral should only take effect when any costs related to these assets are not included in rates, after new rates come into effect. MEUs' counsel suggested this would be "consistent with the intent of the settlement agreement and the GRA as filed, which contemplated new rates taking effect consistent with the start date of any potential deferral on account of a delay in securitization". Finally, the Industrial Group submitted that retroactive application of the deferral would offend a well-recognized ratemaking principle that deferrals should only apply prospectively.

[312] In its reply submissions, NS Power submitted that the intervenors' concerns about "overcollection or double recovery are unwarranted":

- First, the current rates are based on a revenue requirement developed in a prior test year using forecasts that predate these circumstances. Attempting to retroactively attribute specific current costs to that framework would be artificial and unreliable;
- Second, rates were capped in 2023 and 2024, with the result that the Company's full revenue requirement was not funded and therefore these costs have not been recovered;
- Third, in recent years the Company has consistently earned below its allowed return on equity, further confirming that incremental costs of this nature are not being absorbed through existing rates;

- Fourth, the Company is already bearing significant unrecovered costs in the period between January 1 and the issuance of the Board's decision in this proceeding – a period that coincides with peak winter sales and system stress. That burden should not be compounded by requiring the Company to absorb additional costs associated with an initiative that has broad stakeholder support, is plainly in customers' long-term interest, and whose timing is largely outside the Company's control; and
- Fifth, the presence of the earnings cap requiring that anything recovered over 9.25 percent is returned to customers through the FAM provides a safeguard in the, highly unlikely, scenario where earnings reached that level as a result of a January 1, 2026 deferral effective date.

[NS Power Reply Submissions, February 6, 2026, pp. 34-35]

[313] Mr. Madsen also had concerns about NS Power's proposal to defer the depreciation expenses and financing costs at WACC if the securitization is delayed:

While I do not oppose the securitization proposal, I do oppose NS Power's proposal to defer depreciation and financing costs on the assets at its WACC if the securitization is delayed. NS Power has not adequately demonstrated why the delay occurred. Additionally, it is in the interest of all parties, including customers and NS Power, that the details of the securitization are finalized quickly to ensure rate certainty for customers. Allowing for recovery of WACC on unrecovered costs provides a weak incentive for NS Power to ensure the process is completed in a timely manner.

Additionally, I note that the period of delay appears to be a matter of months. It is customary for return on such amounts to be approved by a regulator where there is a substantial delay that is outside the control of the utility. The context of this delay is one that is not substantial. The delay is also not clearly outside the control of the utility.

Accordingly, I support simple deferral of any amounts related to depreciation and financing costs to the extent the securitization is delayed. Simple deferral of only the specific dollar amounts, after review of all supporting calculations for those amounts is appropriate for the above reasons. ...

[Exhibit N-34, p. 120]

3.5.1.2.1 Findings

[314] The approval of the potential securitization is not before the Board in this application. The sole issue in the present matter is whether the Board should approve the securitization deferral. NS Power asked for this deferral in case the securitization is delayed such that it cannot occur, "in whole or in part", by January 1, 2026. NS Power proposed that the depreciation expense and financing costs of the unrecovered net book value of the thermal assets within the scope of the DDA be deferred at WACC on an interim basis. It is now known that the securitization did not occur by January 1, 2026.

Securitization cannot currently proceed in Nova Scotia because the enabling statutory provision has not been proclaimed and regulations to implement this mechanism have not been enacted by the Province.

[315] Given the Department of Energy's submissions, the Board shares the Consumer Advocate's view that, at least at this point, "the achievement of securitization appears to be very much in question". Clearly, the Consumer Advocate is correct when he observed that the "regulatory amendments necessary to facilitate securitization will not happen without the support of the Province". Nevertheless, in their closing submissions, all the customer representatives expressed their support for the eventual securitization of the subject thermal assets:

- Finally, the MEUs would also like to take the opportunity provided by the closing submissions to reiterate their support for NS Power's efforts to securitize approximately \$700 million of assets in the Decarbonization Deferral Account ("DDA") over the GRA period. Securitization is an approach that lowers costs for customers ... (MEUs, p. 4);
- ...the securitization of the DDA assets would result in a significant savings for current NSPI ratepayers, ... While approving securitization is not before the Board today, it is important that the Board give it the appropriate consideration as the assumptions regarding securitization, and its benefits to rate payers, form an important part of the GRA. Should securitization not proceed during the test period, there could be significant financial impacts for NSPI ratepayers, which cannot be avoided. (Small Business Advocate, p. 7);
- A key feature of the GRA and the Settlement Agreement is the securitization of the thermal assets of the Utility, which it values at approximately \$700 million dollars. Securitization would remove the net book value of these assets from Nova Scotia Power's rate base and significantly reduce its revenue requirement for the test years. (Consumer Advocate, p. 9);
- The use of securitization to achieve cost savings was a critical component of the Consensus Agreement from the ratepayer perspective. ... NS Power should continue its efforts to pursue securitization. (PHP, p. 8);
- ... The Industrial Group has consistently supported securitization of NSPI's thermal assets, now contained within the Decarbonization Deferral Account ("**DDA**"). The evidence filed to date confirms that this proposed treatment will yield substantial savings for ratepayers: currently estimated at approximately \$85 million over 2026–2027, ... In the GRA negotiation process, securitization received unanimous support from customer representatives as the preferred solution for financing the DDA assets. ... Not only have customer representatives viewed securitization favourably, but recent credit rating reports from S&P and DBRS Morningstar, also highlight the value of securitization mechanisms more broadly. (Industrial Group, pp. 10-11).

[316] These intervenors do not oppose the proposed securitization deferral, except in one important respect. As noted above, the intervenors do not agree that the deferral be effective retroactive to January 1, 2026.

[317] The Board accepts the evidence of NS Power, Morrison Park, Emrydia and the submissions of the customer representatives that securitization, if allowed to proceed, could benefit ratepayers by lowering financing costs related to the retirement of thermal assets. Past examples that were similar to securitization clearly showed that the result is lower costs for ratepayers. Such processes include the Government of Nova Scotia's purchase of \$117 million of FAM receivables in February 2024. This transaction acted to lower NS Power's borrowing costs and avoid rate shock for customers.

[318] In turn, Morrison Park noted that positive developments affecting NS Power had a favourable impact on the utility's relative borrowing costs going forward, as measured by a reduction in NS Power's bond yield spreads compared to government bonds. Morrison Park indicated that bond markets react favourably to positive developments, typically lowering NS Power's financial and business risks. Morrison Park highlighted that "concrete steps to solve problems at NSPI – such as the securitization of the stranded FAM balances – was rewarded by the markets with lower yields on NSPI bonds".

[319] NS Power has been in a precarious financial situation since its credit rating was downgraded to BBB- in late 2022. Morrison Park confirmed that a further downgrade of NS Power's credit rating "would have serious long-term consequences, as the company would no longer be investment grade. All new issuances of debt would be significantly more expensive than was historically the case". It said this could lead to an

additional \$25 million or more in interest costs per year, due to increased interest rates on new debt and on refinanced debt on maturing long-term bonds. There would also be increased rates due to defaults and penalties to the beneficial financing arrangements received from the Government of Canada for recently approved large projects to support renewables on the grid and improve reliability, such as a 3% increase on NS Power's Battery Energy Storage Project and an increase in the return paid to the Canada Infrastructure Bank from 1.15% to 9.00% on the Wasoqonatl Transmission project for the NS/NB Reliability Intertie.

[320] The Board places significant weight on Morrison Park's evidence. Mr. Colaiacovo, Managing Director at Morrison Park, was qualified as an expert to provide opinion evidence about utility financing. Morrison Park is a Canadian independent investment bank which provides advisory services for mergers, acquisitions and capital raising, and provides expert witness testimony before courts and regulators. About 40% of its work is in the energy and utilities sector. He explained the practical impact of a potential credit ratings downgrade on the borrowing costs incurred by NS Power, which are ultimately borne by ratepayers. He confirmed that prior steps taken to address issues, such as the securitization of NS Power's FAM balance, was "rewarded by the markets with lower yields on NSPI bonds".

[321] It was confirmed at the hearing that a six-month delay in securitization to July 1, 2026, would reduce the estimated \$90 million savings for NS Power and its customers by about one-quarter (i.e., by \$22.5 million). However, if securitization does ultimately proceed, savings could still be realized for the remaining part of the two-year test period and beyond.

[322] As noted above, the approval of the potential securitization is not before the Board in this application. Whether securitization ultimately proceeds is a policy matter for the Province to decide.

[323] NS Power requested the deferral account in case the Province delayed or was not prepared to proclaim s. 35G of the *Public Utilities Act* and enact regulations to allow the securitization to proceed. However, in its closing submissions, the Department of Energy stated that “it could be that under certain circumstances some form of securitization makes sense”. While the Province has shown support for this mechanism in the past by enacting s. 35G in 2024, and by providing a letter of support from Deputy Minister Gatien in May 2025, the Province is not prepared to allow the securitization to proceed at the present time. As canvassed elsewhere in this decision, this position is based on the valuation of the coal plant assets NS Power seeks to securitize.

[324] The only securitization related issue in this application is whether the Board should approve the securitization deferral. The Board finds that it should. The depreciation expenses and financing costs proposed to be deferred relate to assets covered by the scope of the DDA that will continue to be used and useful in the test years. These are costs that would normally have been included in NS Power’s proposed revenue requirements for the test years but, anticipating that the net book value of these assets would be removed from rate base through securitization, NS Power did not include them. While NS Power may have been overly optimistic in doing so, its decision was intended to secure an early benefit for customers from securitization in this general rate application and there is no basis to disallow the recovery of these costs for that reason.

[325] NS Power continues to be optimistic that securitization will occur at some point. However, the Board is concerned about the continuing accrual of these decommissioning and financing costs in a deferral account when they should be included in present rates. This cannot continue indefinitely. To encourage NS Power to deal with this issue on a timely basis, NS Power will only be permitted to earn WACC on this deferral during the test period. After that, subject to a further or other order of the Board, NS Power may only earn at its weighted average cost of debt and must seek leave of the Board, in advance, to continue to accrue amounts to this deferral account after December 31, 2027.

[326] Accordingly, the Board approves the securitization deferral for the thermal assets within the scope of the DDA, including the depreciation expense and financing costs related to these assets. However, the Board finds that the deferral account must only take effect when the new rates are implemented. The Board agrees that it would offend accepted ratemaking principles to retroactively apply the deferral. It would amount to double recovery to the extent that costs related to these assets are already embedded in existing rates.

[327] The Board accepts PHP's description of the problem and why it must deny NS Power's request to retroactively apply the deferral:

Effectively, NS Power is asking to recover costs associated with to-be securitized assets differently than other similar generation assets simply because NS Power has proposed to securitize them, and did not have new rates in place before the assumed securitization period. If permitted, this would provide NS Power with the opportunity to defer and recover costs for the to-be securitized assets in advance of the Board's approval of new general rates for similar assets.

The timing of securitization is not the issue. Consider what would happen in the event securitization never occurs. If NS Power's proposal is approved, it could apply for recovery of the depreciation and financing costs associated with those assets starting from January 1, 2026, even though the Board's approval for new rates associated with the 2026 test year revenue requirement did not occur until sometime later in 2026. This would result

in customers paying more than if securitization was never put forward as a concept in the first place.

In support of its proposal, NS Power attempted to argue that the costs of the assets are not necessarily included in existing rates because of the way rates were capped. But it is NS Power that is in control of the timing of its rate applications. There is no dispute that these same assets were included in the revenue requirements NS Power proposed as part of the 2022-2024 GRA that led to the establishment of existing rates. To the extent that existing rates are not sufficient to meet NS Power's revenue requirements, it remains NS Power's obligation to bring forward GRAs in a timely manner.

[PHP Closing Submissions, January 30, 2026, pp. 7-8]

[328] It is up to NS Power to effectively manage its regulatory calendar. It only filed its GRA in late September 2025, practically ensuring that the matter would not be concluded before year-end. Given what is now known about the Province's position on securitization, NS Power's expectations about completing the securitization by year-end of 2025 were no doubt unrealistic. Notwithstanding its misplaced belief, if NS Power wished the deferral to be effective January 1, 2026, it should have pursued that issue diligently to ensure that it would not offend the well-recognized principle against retroactive ratemaking, as described elsewhere in this decision. The carriage of that issue was within NS Power's control if it wanted the matter resolved before year-end. Failing that, the deferral, once approved, can only become effective when new rates are set by the Board.

[329] There is also an issue about the return to be applied to the balance of the securitization deferral account. The Board notes the concerns expressed by Emrydia but finds that WACC can be applied during the test years as set out above.

3.5.1.3 EIFEL Deferral

[330] NS Power has requested the ability to create a regulatory deferral to allow it to recover an incremental tax expense if an exemption is not enacted by the

Government of Canada with respect to a tax provision entitled the “excessive interest and financing expenses limitation” (EIFEL).

[331] The EIFEL provision was enacted in Bill C-59, effective January 1, 2024. However, in August 2025, the federal government released an update to the EIFEL rules which included an exemption for regulated utilities. The Government repeated its intention in the Fall of 2025 to implement the exemption. To date it has not been enacted.

[332] NS Power elected to remove this potential expense from its forecast revenue requirement because it believes there is a “high potential” that the exemption will be granted. If not granted, it has requested the EIFEL deferral. The parties to the settlement agreement agreed to defer the incremental tax expense of about \$7.5 million over the 2026-2027 test period if the exemption is not allowed.

[333] Doane Grant Thornton confirmed at the hearing that the state of the exemption remained uncertain. It stated that it is not uncommon for uncertainty over such new tax rules to continue over an extended period, including over successive fiscal periods. In the absence of the deferral, Doane Grant Thornton stated it would be appropriate for the expense to be included in the forecast revenue requirement. It agreed that the EIFEL deferral was reasonable.

3.5.1.3.1 Findings

[334] Based on the evidence of NS Power and Doane Grant Thornton, the Board finds it appropriate to approve the EIFEL deferral.

3.5.1.4 PHP Deferral

[335] PHP currently takes service from NS Power under the Extra Large Industrial Active Demand Control (ELIADC) tariff, which is a Below-the-Line (BTL) tariff. The cost-

of-service study supporting this general rate application assumed that PHP would take service under a new Above-the-Line (ATL) tariff on January 1, 2026.

[336] However, that did not occur. On March 31, 2025, NS Power applied to extend the ELIADC tariff for its third term, effective January 1, 2026, until December 31, 2026, inclusive. The Board approved the extension by decision letter dated September 22, 2025 (M12184) but ordered amendments to the tariff and further reporting. Further, in keeping with NS Power's statement that its objective was to apply for a successor tariff in 2025, to be available to PHP in 2026, prior to the PHP Goose Harbour Lake Wind Farm being commissioned, the Board directed NS Power to apply for the successor tariff by December 31, 2025.

[337] NS Power applied for the successor tariff on December 29, 2025 (M12661), requesting approval of the Extra Large Industrial Dispatchable (ELID) Tariff, an ATL tariff. It noted that the intention is that PHP will subscribe to this tariff on, or before, January 1, 2027, as the ELIADC tariff expires at the end of 2026.

[338] As noted above, NS Power's GRA was based on PHP being treated as an ATL customer in the 2026-2027 cost-of-service study. NS Power said it expected the provision of ADC (i.e., Active Demand Control) service to be proposed as a rider to the new ATL tariff and that any approved payments to PHP for ADC services were expected to be recovered from ATL customers. Other proposed features of PHP's ATL treatment included an interruptible credit (equal to the Large Industrial Interruptible Rider (LIIR) credit) and the value of priority interruption service provided, if any (modeled as a 10% premium to the LIIR credit).

[339] NS Power's GRA requested a PHP Deferral to track any revenue differences between the assumptions in the GRA cost-of-service study treating PHP as an ATL customer and the eventual ELID tariff, in the form ultimately approved by the Board. The GRA adopted a clause in the settlement agreement that the PHP Deferral account would apply in the following scenarios:

- the Board's decision on the PHP tariff or ADC rider differs from the ATL GRA tariff assumptions;
- the tariff is not available for PHP to take service under it as of January 1, 2026; or
- PHP decides the outcome of the ADC and tariff processes is not satisfactory.

[340] In response to Undertaking U-2, NS Power estimated that \$18.2 million would accrue in the PHP Deferral account if PHP remains as a BTL customer for the entirety of 2026, and there would also be a \$5.7 million fuel balance captured under the FAM. NS Power also assumed the PHP load in 2026 was the same as that assumed in the GRA. The Industrial Group noted that these amounts did not account for delays in PHP's Goose Harbour Wind Project.

[341] While the PHP Deferral contemplated in the settlement agreement was agreed to by the customer representatives, it is clear from the questioning at the hearing that there may be uncertainty about parts of the scope of the deferral account as between NS Power and some of the customer representatives. The settlement agreement contained a clause that the parties were free to take any position they wished during the Board's review of the PHP successor tariff.

[342] In his closing submissions, the Consumer Advocate noted that, as an ATL customer, PHP will assume significant costs that would otherwise be allocated to other

customer classes. Further, he noted that if PHP considers that the new tariff is not satisfactory, or that the Board does not approve the proposed ATL tariff, PHP could remain a BTL customer under the ELIADC tariff for all of 2026, which would impose additional costs on the other rate classes. The Consumer Advocate stated that there already appear to be areas of disagreement between NS Power and PHP about the proposed tariff. The GRA and the settlement agreement contemplates PHP's firm, plus interruptible load, at a forecast of 65 MW, while PHP takes the view that "the three coincident peak demand determinants applicable to PHP should be set at the firm demand level of 8-MW" (p. 6 of the M12661 application). The Consumer Advocate noted that these "unanswered questions bear directly on the terms of the Settlement Agreement and the resulting GRA".

[343] The Industrial Group noted that the terms about the treatment of PHP in the settlement agreement were "intentionally drafted" and are the lengthiest section of the agreement. It submitted that the PHP Deferral account was "intended to capture only specific variances ordered by the Board" and the only issue in this proceeding "is the proper scope and parameters of the PHP Deferral Account" as reflected in the three above scenarios set out in the settlement agreement. It said that there was no proposed PHP successor tariff at the time the settlement agreement was negotiated, so that the GRA's cost-of-service study made various assumptions about:

... certain load and demand characteristics of PHP under an ATL rate. The COS embeds fuel cost savings and PHP's contribution to fixed costs but does not quantify the value of "active demand control" ("ADC") which was contemplated to be negotiated between PHP and NSPI.

[Industrial Group Closing Submissions, January 30, 2026, p. 8]

[344] The Industrial Group noted that the settlement agreement was signed on August 29, 2025, but that NS Power did not file its application for a successor tariff until

December 29, 2025, despite assuming that the GRA's cost-of-service study was forecast based on receiving Board approval for the successor tariff in time for it to be implemented by year-end. Given that NS Power and PHP controlled the timing of the successor tariff application, the Industrial Group stated that it reserved the right to argue whether the costs sought to be transferred to the deferral account met a prudence test. Further, it noted that in the ELID application (M12661), NS Power appears to ask for "expanded risk mitigation parameters beyond these agreed terms [of the settlement agreement]", noting that the utility uses language such as "including but not limited to..." in referring to variances to be included in the deferral account.

[345] The Industrial Group also referred to NS Power's testimony, which it said appeared to potentially expand the scope of the deferral account:

Q. (Rudderham) I guess I'm trying to clarify what exactly NSPI is looking for approval from the Board for this deferral account because there needs to be some predictability here as to what's going to be deferred and recovered at a later time versus what is not going to be deferred and recovered from other customers. So can you clarify that?

A. (Williams) Yeah. Well, I'm trying to. And I understand the frustration, but I think the reality is that we need to ensure we're not closing the door to something that we just may not be seeing or foreseeing as a result of this tariff application.

I do think we have put forward appropriately worded, appropriately stringent criteria as to what would be applicable or what would be eligible for the deferral. And it goes back to -- when I say principles, it's really those three bullets from the settlement -- or three bullets from the General Rate Application that are based on the Settlement Agreement and then we've expanded on those, expanded on those here in the PHP application to try to give a bit more clarity as to what those items could potentially be. [Emphasis added]

[Transcript, January 8, 2026, pp. 591-592]

[346] The Industrial Group requests that the Board confirm the "defined and limited scope of any deferral account" as described in the settlement agreement and the GRA, asserting that the PHP Deferral should not cover "any and all variables" relating to "whether and when" PHP takes service as an ATL customer. It also asks the Board to confirm that the scope of the deferral account does not include "risks associated with

delays in the Goose Harbour Wind Farm or non-fuel cost changes arising from shifts in PHP's load".

[347] In its report, Bates White concluded that, given the uncertainty surrounding PHP's tariff mechanism for the test period, NS Power's PHP treatment in the GRA was reasonable. It stated:

... NSPI recognizes the uncertainty regarding PHP's tariff for the GRA period, as well as the nature of any load shifting credits PHP may earn under that tariff. NSPI necessarily needs to make assumptions regarding PHP's tariff arrangements in order to complete its cost of service study and GRA Application, and it has done so. Treatment of PHP in the GRA Application also appears consistent with the terms of the Settlement Agreement, which included treatment of PHP details as a key term.

NSPI's assumptions appear reasonable for purposes of the GRA Application, though as NSPI notes, the actual tariff and ADC credits may differ substantially from what NSPI assumes in the GRA.

[Exhibit N-35, p. 29]

[348] However, Bates White also suggested that it would be beneficial for NS Power to confirm "that its PHP Deferral will account for treatment of the Goose Harbour Lake wind project, should the tariff provisions under which PHP ultimately takes service (and receives credits for load shifting) incorporates services, costs, or revenues from the Goose Harbour Lake wind project". While this was confirmed by NS Power on questioning by Board Counsel, the Board observes that the Industrial Group appears to oppose the possibility of this deferral. The Industrial Group said this was not explicitly agreed to by customer representatives and its inclusion in the scope of the PHP Deferral was a departure from the terms of the settlement agreement.

3.5.1.4.1 Findings

[349] NS Power requests a PHP Deferral account to track any variances in revenue between that which would occur based on the assumptions in the GRA cost-of-service study treating PHP as an ATL customer versus that which results from the eventual ELID tariff, in the form ultimately approved by the Board. This deferral account

was expressly contemplated in the settlement agreement, which also set out various assumptions incorporated into the GRA's cost-of-service study about PHP taking service under an ATL rate.

[350] The eventual balance of the proposed deferral account is material. According to NS Power's response to Undertaking U-2, \$18.2 million would accrue in the deferral account if PHP remains as a BTL customer for the entirety of 2026, and there would also be a \$5.7 million fuel balance captured under the FAM.

[351] While the deferral account was addressed in the settlement agreement, the scope of the account is somewhat uncertain, at least based on the Industrial Group's submissions. However, no party opposed the creation of the PHP Deferral Account. The Board recognizes that there could be significant variances to NS Power's revenue requirement depending on the final adjudication of NS Power's application for the PHP successor tariff. The creation of the proposed deferral account, and the assumptions underlying it, do provide some certainty for the utility and the customer classes. The Board finds that it is appropriate to approve the deferral account.

[352] As to the scope of the deferral account, the Board considers that it is best defined as expressly set out in the settlement agreement. There was no evidence about the scope of the deferral account except for that provided by NS Power, and a reference by Bates White. It would be appropriate for customers and other parties to provide evidence on the issue if they consider it necessary. Accordingly, as outlined in part (g) of the "PHP Treatment" section of the agreement, the Board finds that the deferral account will:

... account for any NS Power revenue variances that may arise in 2026 or 2027 from the following scenarios, which costs would be collected/refunded from/to above the line customers:

- (a) where a Board decision on the PHP tariff, including the Active Demand Control Rider, differs from the above the line PHP tariff assumptions included in the 2026-2027 GRA;
- (b) where, for any reason, the PHP tariff is not available for PHP to take service under it as of January 1, 2026; and/or
- (c) PHP determines the PHP ADC and tariff processes outcome is not satisfactory.

[Exhibit N-27, NSEB IR-1, Attachment 1, p. 12]

[353] Further, any amounts to be transferred to the deferral account will be assessed against the various assumptions agreed to by the parties as inputs to the cost-of-service study applied in the GRA, as set out in sections (a) to (f) in the “PHP Treatment” section of the settlement agreement. As with all deferrals, any transfer to the deferral account is subject to review for prudence.

3.5.1.5 GRA Deferral

[354] In its general rate application, NS Power asks for a deferral of its GRA-related costs of the present matter and to collect those costs in rates on a straight-line basis over the two-year test period. Such costs include the costs of NS Power, the consumer advocates and the Board, and the expert consultants for the parties. The amount was forecast at \$4.0 million, but in the settlement agreement the parties agreed to reduce this amount to \$2.0 million, with \$1.0 million recovered in each of the two test years.

[355] NS Power equated the treatment of these GRA-related costs to the regulatory deferral approved by the Board in its *2023-2024 GRA Decision*, in which the Board approved the company’s request to defer and create a regulatory asset for the costs of the Cost-of-Service Study, Line Loss Study, and Climate Change Adaptation Plan filed in the present application (or by December 31, 2025, whichever was sooner). In the *2023-2024 GRA Settlement Agreement*, the parties had agreed to recovery of the costs

of the Cost-of-Service Study and the Line Loss Study in this GRA application, which was confirmed by the Board. The Board also approved the recovery of the costs of the Climate Change Adaptation Plan in this proceeding.

[356] In Undertaking U-9, NS Power was asked to confirm the costs of the Cost-of-Service Study and the Line Loss Study. The company replied that the Cost-of-Service Study costs were included in the total GRA costs. It stated that the cost of the 2026-2027 GRA and Cost-of-Service Study (including the Line Loss Study) was \$1,332,440 as of December 2025, subject to adjustments after the close of the 2025 fiscal year.

3.5.1.5.1 Findings

[357] NS Power's costs for preparing and presenting a general rate application have not previously been allowed to be recovered in the test period of that application because they represent costs incurred before the test period. Such costs should be covered in the company's current regulatory affairs budget. Rather, costs approved in a general rate application are intended to apply to costs that are to be incurred prospectively.

[358] The Board is concerned about pushing operating costs into deferrals because they would thus attract a return. The Board has previously noted that if a utility believes it is appropriate to smooth a cyclical type of expense over a regularly recurring period, it expects the utility to explore other options, such as normalizing such costs in its expenses, rather than an option that would attract a rate of return: *NSPML 2024 Cost Assessment* Decision, 2023 NSUARB 231, para. 22.

[359] There are exceptions to the general rule against retroactive ratemaking, but there are specific criteria to justify the deferral of operating costs, which were canvassed by the Nova Scotia Regulatory and Appeals Board in *Halifax Regional Water Commission 2026-2027 General Rate Application, 2025 NSRAB 142 (M12257)*:

[185] Utility regulators in Canada routinely do not allow retroactive ratemaking. This is because traditional cost of service ratemaking involves estimating future annual utility operating expenses over test years. The revenue requirement for the test years is the sum of the allowed projected operating costs plus a rate of return on the utility's capital rate base. The entire process underpinning proposed rates is prospective. Everyone involved in the process knows that projecting expenses and revenues is not an exact science. While there will invariably be differences between projected and actual figures, provided a utility meets its overall revenue requirement, no rate increases are necessary.

[186] The prohibition against retroactive ratemaking is not absolute. Certain forms of retroactive ratemaking are well recognized. They include retroactive adjustments to interim rates and established true-up mechanisms where projected costs included in rates are trued up, either up or down, after actual costs are known. An example of the latter is NS Power's Fuel Adjustment Mechanism. The rationale underpinning these types of exceptions to the rule against retroactive ratemaking is that customers are given notice up front that the rate is subject to change.

[187] The Board recently considered the availability of retroactive ratemaking in situations outside the more recognized forms. NS Power sought to recover \$26.4 million in operating costs incurred because of Hurricane Fiona (2024 NSUARB 116). The costs had already been incurred at the time of the application, so it was a case of retroactive ratemaking. The Board said:

[72] The Board is in general agreement with the Alberta Court of Appeal's approach to retroactive ratemaking. Where there is no express statutory prohibition against retroactive ratemaking, it is beneficial for the Board to have some flexibility to address extraordinary or novel situations by relaxing the rule against retroactive ratemaking so that the interests of both the utility and its ratepayers can be considered, without opening the door to endless rate adjustments.

[188] ... In the *Hurricane Fiona* Decision, the Board outlined factors that should be considered when deciding whether to exercise its discretion and allow retroactive ratemaking where the traditional exceptions were not applicable. In that case, the issue was framed as allowing a deferral account so the Hurricane Fiona operating costs could be collected over time, as opposed to expensing them in the year they were incurred. These factors can be applied to retroactive ratemaking generally. They include:

- Whether the expenses are extraordinary or unusual or result from an event which is unusual or extraordinary.
- Whether the expenses are beyond the utility's control and could not have been reasonably anticipated.
- The expenses must be "significant".

- Whether, if not incorporated in rates, the expenses will have a material impact on the utility's financial condition.
- Whether, if granted, the recovery of expenses that have already crystalized will provide significant benefits to ratepayers.

[2025 NSRAB 142 (M12257), paras. 185-188]

[360] The Board finds that the present instance clearly does not fall within the above exceptions. The GRA-related expenses are not due to extraordinary or unusual circumstances; the costs are not significant, nor do they have a material impact on the utility's financial condition; and the costs are not beyond the utility's control. Such expenses were anticipated and should have been included in the prior GRA if they were not already.

[361] The Board denies NS Power's deferral of its GRA-related costs, except for the costs related to the Cost-of-Service Study (COSS) and the Line Loss Study. In Undertaking U-9, NS Power stated that the cost of the 2026-2027 GRA and COSS (including the Line Loss Study) totaled \$1,332,440 as of December 2025. In its compliance filing, the Board directs the company to confirm the amount of costs related to the COSS and the Line Loss Study (as it was asked to do in Undertaking U-9) and to deduct the other GRA-related costs from the \$1 million amounts included in each of the 2026 and 2027 revenue requirements.

3.5.1.6 Payment of Interest on Deferral Accounts

[362] The payment of interest to NS Power on its deferral accounts is subject to s. 64AB of the *Public Utilities Act*. In its 2023-2024 GRA Decision, the Board concluded that it was appropriate to exercise its discretion under s. 64AB(3) to set interest on the deferrals at NS Power's WACC. In its subsequent decision related to the 2025 Demand Side Management Cost Recovery Rider (DCRR) (2024 NSUARB 216, M11912), the Board canvassed various issues related to s. 64AB and stated it would establish a generic

proceeding to more thoroughly address and consider issues about the application of that provision. Board Counsel has engaged London Economics International LLC to prepare a report about these issues. In the interim, the Board finds it appropriate to continue to exercise its discretion under s. 64AB(3) to set interest on deferral and variance accounts at NS Power's WACC.

3.6 Rate Base

[363] NS Power's rate base consists of the physical assets and related construction work in progress the utility has invested in to provide power to its customers, such as generating stations and transmission lines. It also includes materials and supplies inventory and a working capital allowance. Rate base further includes financial assets such as a long-term income tax receivable and regulatory deferrals, net of regulatory liabilities. Doane Grant Thornton reviewed and verified NS Power's calculations of forecasted average rate base of \$5.58 billion in 2026 and \$5.89 billion in 2027.

[364] The calculation of the forecasted rate base is important because it represents the invested balance used to determine NS Power's forecasted return on equity. It is also fundamental to the calculation of depreciation and amortization expenses, as these expenses are based on the invested balances.

3.6.1 Capital Additions

[365] NS Power's capital outlook for 2026-2027 for additions to Plant reflects the company's best estimate of capital investment over the test years at a point in time. The test period investment is intended to support the continued safe delivery of electricity service and ongoing environmental compliance. It is also meant to align with Renewable Electricity Standards and the requirement to phase out coal by 2030. Finally, the proposed level of capital investment over the GRA test period is also aimed at allowing

the company to continue executing on its 5-Year Reliability Plan while continuing to meet the requirements of a growing customer base.

[366] Sustaining NS Power's asset base through capital re-investment generally results in rate base growth. Similarly, capital investments required to comply with regulations and meet the needs of an expanding customer base also drive growth in rate base. In this context, NS Power's average capital assets will continue to increase over the 2026-2027 test period as the company continues to invest in its system. This increase in rate base will be partially offset by NS Power's planned securitization of the assets within the scope of the DDA, assuming of course, that securitization proceeds. If securitization does not proceed, NS Power's rate base will continue to include the assets within the scope of the DDA.

3.6.1.1 Findings

[367] NS Power's estimated capital investment for the GRA test period amounts to \$671.3 million in 2026 and \$556.1 million in 2027. The capital additions to rate base for the test period have generally been approved by the Board in prior ACE Plan proceedings and other capital expenditure approval applications. However, they also include projects that have not yet been approved by the Board but have been submitted for approval in NS Power's 2026 ACE Plan. In response to NSEB IR-92, NS Power provided a list of capital projects that have not yet been approved by the Board but have been included in the capital budget for the GRA application. Further, in response to NSEB IR-92, NS Power stated:

NS Power's capital forecast is completed at a portfolio level based upon the anticipated capital investment requirements at the time of GRA forecast development. Certain investments that are included in the test period may not advance during the test period and other projects are likely to differ in the timing of investment as NS Power utilizes its asset management framework to refine the capital plan. While certain investments included in the GRA may not advance, or will advance on a differing timeline, NS Power expects that

other capital investments will take their place and the overall level of expected capital investment will be similar to that which is included in forecast.

[Exhibit N-27, NSEB IR-92]

[368] During the hearing, the Board noted that the response to NSEB IR-92 included 39 projects with a total forecast 2026 spending of \$218 million. The Board also noted that NS Power's recently filed 2026 ACE Plan (M12619), shows total forecast 2026 spending for projects (excluding capital routines) yet to be approved by the Board of roughly \$223 million. However, the 2026 ACE Plan includes 20 projects for approval and 47 projects for subsequent submittal in 2026 for a total of 67 projects. Therefore, even though the GRA forecast for 2026 capital spending for projects yet to be approved by the Board is close to the forecast for 2026 ACE Plan capital spending for projects yet to be approved by the Board, the actual projects appear to be quite different.

[369] NS Power explained this discrepancy as a matter of timing between when the GRA projects list was developed versus when the 2026 ACE Plan was prepared. Over this time, the company used its asset management mechanism to update its asset condition and criticality assessment, which resulted in changing priorities for a number of projects. Nevertheless, the overall expected 2026 capital spending estimates in the GRA forecast and the 2026 ACE plan forecast are fairly close. In addition, in Undertaking U-21, NS Power provided a comparison of its actual 2023 and 2024 capital spending to the 2023-2024 GRA forecast spending for those years. In total, the actual capital spending over that period was relatively consistent with the GRA forecast.

[370] During the hearing NS Power also confirmed that it will manage its capital expenditure program over the test period to match the GRA forecast. Therefore, although there is some uncertainty with the capital project additions that are included in the GRA,

because a number of projects are not yet applied for, or not yet approved, the Board finds the total forecast spending on capital additions in the test period to be reasonable.

3.6.2 Maritime Link Capital Projects

[371] NS Power has four Maritime Link transmission capital projects that, by Board Order, have historically been excluded from rate base. The original intent of these projects was primarily to facilitate Nalcor's (now Newfoundland and Labrador Hydro) intended energy export to third parties outside of Nova Scotia. NS Power's expectation when they were built was that the benefit of these projects to Nova Scotia customers, expected to be OATT fees on the exports, would offset the capital and operating costs of these projects. In the 2023-2024 GRA, NS Power requested these projects be included in rate base. It stated that rather than export this available surplus energy, it was retaining it in Nova Scotia to serve provincial requirements, but that the overall benefit of these projects, albeit not the originally expected benefits, outweighed the costs of the projects.

[372] In its *2023-2024 GRA* Decision, the Board did not approve inclusion of the projects in NS Power's rate base. However, the Board defined the test NS Power had to meet to include those assets in rate base. It had to show that the benefits of these projects outweighed the costs to ratepayers. The Board's test stipulated that for a minimum of four consecutive quarters,

- (a) the wheeling tariff revenue;
- (b) the net economic value of NS Power purchases of additional Nalcor surplus energy (based on actual results following the methodology used in Undertaking U-64); or
- (c) a combination of wheeling tariff revenue and the economic value of purchased Nalcor surplus energy,

is at least equal to the combination of depreciation, financing costs, operating costs, and re-dispatch costs.

[373] In the current GRA, NS Power requested Board approval to include the four Maritime Link projects in its rate base, claiming that the company has met the Board test. NS Power's calculation of benefits from the projects in its quarterly benefit reports includes two types of surplus energy: "additional energy" and "bilateral sales". During the hearing in this matter, NS Power was asked to provide an undertaking to show how the Board's test was met. In Undertaking U-24, NS Power provided the calculations it used to confirm it had met the Board's test. Further, in Undertaking U-25, NS Power stated that it purchases market-priced energy from Newfoundland and Labrador Hydro through two mechanisms. NS Power defines these two types as "surplus energy transacted under the Energy Access Agreement" and "bilateral market-priced energy". NS Power asserts that both types of energy are market-priced energy and that their treatment is consistent with the approach in the 2023-2024 GRA proceeding's Undertaking U-64.

3.6.2.1 Findings

[374] The Board notes that Undertaking U-64 in the 2023-2024 GRA referred to the forecast NSP Maritime Link Incorporated surplus energy purchases. While not specifically defined, the Board agrees that, in the context of these specific projects, "surplus energy" means all surplus, including "surplus energy transacted under the Energy Access Agreement" and "bilateral market-priced energy". As such, the Board finds that NS Power has demonstrated through Undertakings U-24 and U-25 that it has met the test for inclusion of the Maritime Link transmission projects in rate base.

[375] The Board notes that inclusion of these projects in rate base is only effective on a go-forward basis. NS Power is not permitted to recover any depreciation expense

already incurred or any lost return on rate base associated with these projects from any period prior to the date of the Board's decision in this GRA. To be clear, the amount to be included in rate base for these projects is the net book value of these assets as of the date of the Board's Order in this matter.

[376] The Board also offers one further caveat. In this particular instance, the Board found that customers received benefits from surplus energy from Newfoundland and Labrador Hydro regardless of whether the energy was market-priced energy transacted under the Energy Access Agreement (EAA) or through bilateral arrangements outside of the EAA. However, there may be situations where the distinction between these two mechanisms is relevant. For example, an assessment of whether there has been compliance with rights and obligations of the parties under the EAA may require that the focus be on energy transacted under the agreement to the exclusion of other bilateral arrangements.

3.6.3 Valuation and "Writing Down" of the Rate Base

[377] The Department of Energy requests that the Board take steps to ensure that NS Power's coal assets are written down by an amount that the Board deems appropriate based on a transparent, comprehensive review of asset lives and amortization schedules, aligned with coal phase-out commitments and the public interest. The Department submits there is a solid legal and regulatory pathway for the Board to require NS Power to bear coal asset write-downs, particularly for life-extension and reinvestment decisions made in the shadow of a known 2030 coal phase-out.

[378] The Department's position is premised on a belief that the value of NS Power's coal plants is "over-inflated" and "that ratepayers should not be asked to carry the cost of outdated infrastructure". It argues:

Nova Scotians should only be paying for infrastructure that reflects its real remaining usefulness. There remain legitimate questions around whether NS Power is employing actual *values that reflect real remaining usefulness*. [Emphasis in original.]

[Department of Energy Closing Submissions, p. 7]

[379] The Department attributes this over-inflated value of rate base to NS Power's failure to conduct timely depreciation studies and the utility's imprudent investment in coal assets after the lifespans of these assets were materially shortened by government policies. The Department submits that, at least as early as 2016, NS Power knew that its coal assets must be retired by 2030 but did not take this into consideration when valuing its assets. The Department said:

In the 2022 GRA, the Department submitted that the Company knew as of 2016 that coal must be retired by 2030 and yet it did not take this into consideration when valuing its assets. It is common that accounting and regulatory standards require impairment (write-downs) when early retirement is probable. Nova Scotia's coal-retirement trajectory has been clearly defined in legislation and federal policy for some time, making impairment not only probable but foreseeable. These regulatory changes were well known and NS Power's failure to reflect them in asset valuations has resulted in ratepayers bearing costs that should have been recognized and allocated differently.

[Department of Energy Closing Submissions, p. 7]

[380] The Department submitted that the settlement agreement relating to NS Power's last depreciation study ((M03665), 2011 NSUARB 64) extended the service lives of NS Power's coal-fired generation stations and created a "regulatory obligation" to review these service lives when federal regulations in 2016 required all coal facilities to be retired by 2030. The Department also submitted that NS Power's 2020 Integrated Resource Plan referenced 2040 as the target for phasing out coal plants, which the Department said was inconsistent with this federal legislation.

[381] The Department said that NS Power continued to invest in thermal energy generation while eschewing lower cost renewable resources. The Department submitted this also exposed ratepayers to higher and volatile fuel prices. It submitted that NS Power

did so in the face of clear government policies and legislation mandating the phase-out of coal-fired generation of electricity and, therefore, the Board may properly conclude that shareholders, not ratepayers, should bear the risk of stranded assets.

[382] The Department posits that NS Power's actions were motivated by a desire to maintain a rate base that was higher than it should have been to boost its allowable returns. The Department says this resulted in higher rates for customers.

[383] The Department cites the United States Supreme Court decision in *Smyth v Ames*, 169 US 466 (1898) and the "Alberta based – Utility Asset Disposition (UAD) Line of Cases" to support its position that assets must be "used and useful" to be included in rate base, that utilities – not ratepayers – bear the risk of unrecovered costs, and that utilities can be forced to absorb losses through capital write-downs.

[384] The Department said the Board has the authority to review NS Power's depreciation practices under s. 30(2) of the *Public Utilities Act* and the authority to correct the valuation of the property under s. 33(2). These provisions read:

Power to determine value of property of utility

30 (1) The Board may at any time, with the assistance of such engineers, accountants, valuers, counsel and others as it deems wise or advisable to employ, inquire into and determine the extent, condition and value of the whole or any portion of the property and assets of any public utility used and useful in furnishing, rendering or supplying a particular service to or for the public, as of a date to be fixed by the Board.

(2) The Board shall determine the value of such property and assets on the basis of the prudent original cost thereof or by such other method as the Board may from time to time prescribe, deducting therefrom the amount of the accrued depreciation of such property and assets as determined by the Board.

(3) For the purposes of this Section, annual and accrued depreciation shall be calculated by the straight line method, so called, or such other method as the Board may from time to time prescribe.

(4) The Board may make such rules and regulations to facilitate inquiries under this Section as it may deem convenient, and the rules and regulations so made shall be binding on all public utilities.

(5) The Energy Board shall, with the assistance of such engineers, accountants, valuers, counsel and others as it deems wise or advisable to employ,

(a) inquire into and determine the extent, condition and value of the whole or any portion of the property and assets of Nova Scotia Power Incorporated used and useful in furnishing, rendering or supplying a particular service to or for the public, no later than March 31, 2024; and

(b) set different levels of return on equity for different classes of capital assets of Nova Scotia Power Incorporated to ensure that investment incentives are aligned with ratepayer objectives as submitted to the Board in a hearing for a rate change.

...

Duty of utility to furnish information

33 (1) Every public utility shall furnish to the Board from time to time, and as the Board may require, maps, profiles, contracts, reports of engineers and other documents, records and papers, or copies of any and all of the same in aid of any investigation and to determine the value of the property of such public utility, and every public utility shall co-operate with the Board in the work of the valuation of its property in such further particulars and to such extent as the Board may direct.

(2) The Board shall, thereafter, in like manner, keep itself informed of all extensions and improvements or other changes in the condition of the property of the said public utilities, and from time to time may revise and correct its valuation of the property of such public utilities.

(3) To enable the Board to make such changes and corrections in its valuation, every public utility shall report correctly to the Board changes in its property and file with the Board copies of all contracts for changes and improvements at the time the same are executed.

[385] In its reply submissions, NS Power said it is entitled to a “fair return” based on the “regulatory compact”. It submitted this is a fundamental principle of public utility regulation recognized as early as a hundred years ago by the Supreme Court of Canada in *Northwestern Utilities Ltd. v Edmonton (City)*, [1929] SCR 186, and more recently in *ATCO Gas & Pipelines Ltd. v Alberta (Energy & Utilities Board)*, 2006 SCC 4. NS Power also referred to decisions of the NSUARB (2012 NSUARB 227 and 2023 NSUARB 12).

[386] NS Power noted that its application in Matter M03665, the proceeding dealing with its last filed depreciation study, assumed retirement dates by 2030 for all steam generation units (including coal units) except for Point Aconi (2039) and Trenton 6 (2037). This was because of “further carbon emissions regulations and a new anticipated

federal government framework”. The application proposed to accelerate depreciation rates to account for shorter lifespans than previously estimated.

[387] NS Power further noted that expert evidence in that matter, on behalf of Board Counsel and customer representatives, “disagreed with NS Power’s assumed retirement dates claiming that, despite NS Power’s reliance on and reference to anticipated environmental regulations and policy, there was no support to use the accelerated retirement dates”. The parties agreed to resolve these matters in a “black box” settlement agreement to lower rates for customers in the next general rate application and this was approved by the NSUARB.

[388] The approved depreciation rates were implemented in NS Power’s next general rate application in 2013-2014. NS Power did not file another rate application until 2022, its most recent past general rate application. NS Power said many shifts and changes in government environmental policy related to coal-fired electricity generation occurred between these two applications.

[389] NS Power highlighted that under two different agreements, the first of which was in effect between 2015 and 2019, and the second of which came into effect on January 1, 2020, Canada and Nova Scotia agreed that federal requirements relating to coal-fired generation units would not apply in Nova Scotia. These agreements recognized a sufficient equivalency between the regulations in Nova Scotia and Canada. NS Power said because of these “Equivalency Agreements”, there was no requirement in Nova Scotia to retire coal generation plants by 2030. NS Power said this requirement was not established until late 2021, when both the federal and provincial governments accelerated their decarbonization policies.

[390] In its 2023-2024 general rate application, NS Power discussed the depreciation of its coal assets and proposed a mechanism to deal with the recovery of the remaining undepreciated and decommissioning costs associated with these assets:

... The retirement and remaining useful lives of the Company's thermal plants is the input that would drive the most material change in the Company's forecast depreciation expense. With the amendments to the Renewable Electricity Regulations, implementing the requirement for 80 percent renewable generation 2030 RES, and the passing of the EGCCRA, NS Power now has a greater degree of certainty on the timing of retirement of its coal fleet; however, for units no longer used and useful beyond 2030, the retirement timeline would result in significant increases to depreciation expense. In an attempt to mitigate rate impacts arising from these developments, the Company is seeking approval of a DDA, a regulatory asset that effectively eliminates the requirement for a depreciation study for the thermal plants that are incorporated within this regulatory asset and provides flexibility on recovery of the remaining Net Book Value (NBV) of those assets.

[M10431 Exhibit N-16, p. 42]

[391] In the related settlement agreement, the parties agreed in principle to a DDA to recover the net book value and unrecovered decommissioning costs of NS Power's undepreciated thermal assets. They also agreed to engage constructively in a consultative process to confirm the practices and procedures that would be followed to establish the DDA. As with the "black box" settlement in 2011 this had the effect of mitigating the rate impact for customers at the time by avoiding the acceleration of depreciation.

[392] In its reply submissions in this proceeding, NS Power also argued that the UAD decisions and the principles those decisions extracted from the Supreme Court of Canada's precursor "Stores Block" decision (*ATCO Gas & Pipelines Ltd. v Alberta (Energy & Utilities Board)*, 2006 SCC 4) have historically had no application outside of Alberta. NS Power said the Department's reliance on the UAD decisions was "fundamentally incorrect" because its coal assets are not stranded but continue to be "used in providing utility service and are anticipated to be used in such a capacity for a number of years to come". Moreover, NS Power submitted that the UAD line of cases

was “brought to an effective end” by the Alberta Court of Appeal decision in *ATCO Electric Ltd. v Alberta Utilities Commission*, 2023 ABCA 129.

[393] Regarding the Department’s reliance on *Smyth v Ames*, NS Power said:

Similarly, the DOE’s submissions refer to and appear to rely upon the USSC 1898 decision in *Smyth v. Ames*. That decision, somewhat ironically, relates to the USSC’s ruling that a Nebraska state law which capped railroad freight rates was unconstitutional because it was confiscatory in nature by preventing railroad companies from earning reasonable compensation for their services and, therefore, violated the 14th Amendment. As a result, *Smyth v. Ames* also is not relevant and has no applicability to the current context.

[NS Power Reply Submissions, p. 19]

3.6.3.1 Findings

[394] A utility is entitled to the opportunity to recover its prudently incurred costs in providing service and an opportunity to earn a reasonable profit – no more and no less. While the Board can disallow costs found to be imprudent or unreasonable, absent such a finding, a utility’s costs must be reflected in the rates paid by customers. The Board cannot disallow the recovery of legitimate costs to make rates more affordable.

[395] Utility investors provide the upfront capital required to purchase or construct utility infrastructure to serve customers, and customers who use that infrastructure repay those costs over time as they receive the benefits of service. To attract and retain this investment, investors are given the opportunity to earn a fair return on the capital invested, as well as ultimately recoup the amounts invested.

[396] This was addressed in detail in the NSUARB’s decision in NS Power’s last general rate application (2023 NSUARB 12, paras. 36-41 and 227-237) and is discussed in more detail later in this decision.

[397] In essence:

A public utility is obligated to provide services that are reasonably safe and adequate and is entitled to compensation therefor by the charging of rates that are not unjustly discriminatory and will provide the public utility with sufficient revenue to enable it to pay its operating expenses including depreciation and income taxes, and have net earnings

sufficient to enable it to obtain and service normal and needed capital requirements. It is expected to meet reasonable demands for additional services and to conduct its affairs with efficiency.

[(*Public Utilities Board*) v *Nova Scotia Power Corporation*, (1976) 18 NSR (2d) 692 (NSSC,AD), para. 26]

[398] As described by the Supreme Court of Canada in *Northwestern Utilities Ltd. v Edmonton (City)*, [1929] SCR 186, a fair return means “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”. A low return on rate base may discourage investment in the utility. It may also lead to a poor credit rating, which will increase its borrowing costs. This may result in the utility's rates increasing just to cover additional borrowing costs. It may even cause it to be excluded from participating in some debt markets altogether.

3.6.3.1.1 The Value of the Rate Base

[399] The “value” of NS Power's rate base, as framed in the Department's submissions, is based on an historic concept that has been displaced by the widely accepted prudent original cost method for valuing utility assets. The prudent original cost approach, which is explicitly referenced in s. 30(2) of the *Public Utilities Act*, is the default valuation method under the statute, and has been explicitly so since 1943 (*Public Utilities Act*, SNS 1943, c 2, s 29(2)).

[400] Two witnesses in this proceeding were qualified as experts in utility depreciation. Mr. Wiedmayer (Gannett Fleming) prepared the depreciation study filed by NS Power in support of its application. This study is based on the original cost method. Likewise, Board Counsel consultant, Mr. Madsen, noted that “Depreciation recovers the original cost of any investment added into utility rate base, such recovery occurring over

the expected useful life of the assets”. Neither expert suggested in any way that the value concept advanced by the Department in its closing submissions was an appropriate method to determine the value of rate base or depreciation rates. The Department filed no evidence and conducted no cross-examination of these depreciation experts, so neither of them was provided with any opportunity to respond to or address the theory raised by the Department in its closing submissions.

[401] In *Principles of Public Utility Rates* (Second Edition; Public Utilities Reports, Inc., 1988), Professor Bonbright reviewed the historical development of the legal and regulatory principles for valuing a utility’s rate base (note that his second edition dates back nearly 40 years and does not capture developments in this more recent period). He noted:

For many years the major division of practice and opinion on these issues of asset revaluation has been between the position that as long as the assets remain "used and useful" for their intended purposes, they should stay in the rate base at their original costs, subject only to systematic annual deductions for physical and functional depreciation; and the position that the costs should be written up and down so as to take account of major changes in construction costs or in general price levels. The first position is that of the original-cost net-investment principle of ratemaking - a principle strongly espoused by the FERC (and its predecessor FPC) and FCC, and accepted, with or without qualifications, in the majority of state jurisdictions. The second position is most frequently referred to as the fair value principle – a principle no longer held legally mandatory throughout this country but still accepted in a considerable minority of states (a dozen or less at last count).

[*Principles of Public Utility Rates*, p. 212]

[402] Bonbright refers to *Smyth v Ames* as the “original and most famous pronouncement of the fair value standard”. The fair value standard was the subject of much criticism over the years. This included what Bonbright referred to as the “vicious-circle criticism” – the fact that the value of the assets depends on the earnings they are able to derive, which is the very question at issue in a rate case (i.e., the value of the rate base will be used to determine rates and the revenue derived from rates will inform the value of the rate base).

[403] Bonbright notes that out of this criticism sprung the cost-based approach to valuation:

Impressed with the force of the vicious-circle argument, many writers have gone beyond the point of insisting that ratemaking value must be given a special interpretation in order to qualify it as a plausible rate base. They have also asserted that the measure of a rate base is necessarily cost and not value in any accurate sense. Consistently with this view, they have insisted that the former debates as to the merits of an original-cost rate base versus a fair-value rate base should have been converted into debates as to alternative standards of costs, including various types of replacement cost and various versions or modifications of original cost. The whole philosophy of a fair-return standard of ratemaking, they have declared, is a cost-of-service philosophy. On no account, therefore, should it be compromised or confused by a backdoor introduction of value-of-service criteria of reasonable public utility rates in the guise of value standards of the rate base.

[*Principles of Public Utility Rates*, p. 217]

[404] Bonbright describes two major advantages of an original cost rate base. First, it is administratively superior as it lends itself to quicker and more definitive determinations of value, minimizing expenses to all parties and the regulator. Second, it facilitates access to capital on favourable terms and helps to maintain credit. On this later point, Bonbright states:

For, although original costs will have become fixed costs at the time of a rate case, they are not fixed cost when first incurred, and it is at this time that investors must balance, *ex ante*, the expected future return on any proposed investment against the presently required outlay of capital. In other words, what induces investment is the expectation of a return on (and return of) costs that will have become sunk as soon as the investors have made their commitments. Whatever scheme of rate regulation will put investors in a position to draw this balance between present outlay and anticipated future return with the most confidence is the scheme most likely to permit a well-managed company to maintain sound financial health at a minimum cost of capital to the consumers.

[405] According to Bonbright (p. 216), “Fair value theory does not appear to be an especially fecund source of logic”. He states that the fair value standard pronounced in *Smyth v Ames* was renounced by the United States Supreme Court in *Federal Power Commission v Hope Natural Gas Co.*, 320 US 591 (1944) (around the same time that the prudent original cost method was first explicitly referenced in the *Public Utilities Act* in Nova Scotia).

[406] The National Association of Regulatory Utility Commissioners' (NARUC's) *Public Utility Depreciation Practices* (1996), referenced in Mr. Madsen's evidence, describes the "value concept" and the "cost allocation concept" in the context of depreciation practices:

Value Concept

The value concept assumes that all depreciable plant, due to forces such as obsolescence, wear and tear, and inadequacy, tends to diminish in value or worth with the passage of time. This value reduction may be dramatic—as when one purchases a new automobile. The new owner needs to do little more than drive it off the dealer's lot in order to put it in the classification of a "used car" with a value often substantially less than the purchase price. On the other hand, the reduction in value may occur much more slowly. For example, heavy duty manufacturing machinery will continue to perform the same operations in the same efficient manner for many years. Depreciation, in this sense, may not be consistent. If manufacturing machinery were producing a product that was in heavy demand for many years and suddenly lost its market, the machinery would rapidly lose value.

All other things being equal, on the day before this sharp demand decrease, the machinery would be nearly as valuable in the production of goods as the day it was first installed (assuming it had been kept in good repair). However, the day after the market disappeared the machine would be practically worthless or valueless.

Similarly, the installation of a new technology offering new or different services may cause existing plant to have little or no customer value. For example, a computerized supervisory control and data acquisition system (SCADA) may make the existing use of chart and pen recorders and the manual operation of gas city gate station valves unnecessary and uneconomical.

This situation suggests that depreciation can be determined through a series of periodic appraisals or estimates of plant value. The decrease in value between such estimates is regarded as a measure of the depreciation attributable to the period between estimates. The estimates could be based on the reproduction cost, market value, or earnings value of the property. Estimates may recognize the changing purchasing power of the dollar or they may be confined strictly to original cost terms. In all cases, some measure of depreciation occurring between estimates can be determined. The customary method is for a competent appraiser to study the effect of factors such as obsolescence, inadequacy, and public requirements, as well as to conduct a physical inspection of the property, or a scientific sample of it, to determine its loss in value since it was first constructed. Regardless of the method employed, in order to achieve consistency, the successive estimates must be made in the same way.

It would, however, be a staggering undertaking to attempt such estimates on an annual basis for complex and extensive utility plant. Therefore, the practice of conducting annual estimates has found little application in the utility industry. It is particularly cumbersome and inadequate because utilities need to record depreciation on a monthly basis for earnings and expense reports. A further complication, of course, is that major technological improvements tend to make questionable any year-to-year measure of depreciation that is determined by this process.

Cost Allocation Concept

This concept recognizes the original cost of the asset as a prepaid expense. As such, it must be allocated to specific accounting periods and realized on income statements during the time the asset is providing service. The unallocated amount, often called net plant or net book (gross plant less accumulated depreciation), is recorded on the asset side of the balance sheet. The cost allocation concept satisfies the accounting principle of matching expense and revenues.

On the income statement, the inflow of resources is revenue. The outflow is expense. Using up the productive capacity of assets in an accounting period is recorded in accounting records as depreciation expense.

As used above, "cost" is based on the cost valuation principle of accounting, with cost being a surrogate for value. The amount of money used to purchase the asset is the basis for the entry in accounting records. This amount is regarded as being definite and immediately determinable. The accounting objectives of verifiability and neutrality are also satisfied.

Equally important to the proper estimation of current net income is the recovery of the investment over its useful life. Depreciation accounting cannot, automatically and of itself, result in the recovery of investment in property. However, if revenues are adequate to cover depreciation expense in addition to other current expense, the investment will be recovered. On the other hand, if revenues are not sufficient to cover the depreciation expense, the investment will not be fully recovered. Recognition of depreciation merely records the fact that costs are being incurred. [Emphasis added]

[pp. 11-12]

[407] More recently, NARUC's publication for the United States Agency for International Development, *Depreciation Expense: A Primer for Utility Regulators* (May 2021), states:

The value concept for determining regulatory depreciation is based on periodic estimations of the asset value. The decrease in the estimated value of the asset can be considered as a measure of the value of depreciation for the corresponding period. The estimation can be made either in terms of the replacement cost, the market value, or the earnings value of the asset, through physical inspections or sample checks regarding obsolescence, wear and tear, and inadequacy of the asset.

However, the value concept is not commonly used for determining the value of regulatory depreciation as it is highly burdensome and creates significant uncertainty both for the regulator and the regulated utility. NARUC (1996, p.11-12) describes the significant drawbacks of the value concept approach:

It would (...) be a staggering undertaking to attempt such estimates on an annual basis for a complex and extensive utility plant. Therefore, the practice of conducting annual estimates has found little application in the utility industry. It is particularly cumbersome and inadequate because utilities need to record depreciation on a monthly basis for earnings and expense reports. A further complication, of course, is that major technological improvements tend to make questionable any year-to-year measure of depreciation that is determined by this process.

In the cost allocation concept, the original cost of an asset is treated as a prepaid expense. The value of regulatory depreciation is then determined by allocating this expense to specific accounting periods during the time the asset is providing service. The depreciation expense allocated in each accounting period is logged on the regulated entity's income statement, while the unallocated amount, the 'net asset value,' is logged as an asset in the balance sheet.

The cost allocation concept is considered the most appropriate, and it is the one that regulators use for determining the value of depreciation in the context of cost-reflective tariff setting. NARUC (1996, 12) highlights the advantages of the cost allocation concept approach:

The cost allocation concept satisfies the accounting principle of matching expense and revenues. On the income statement, the inflow of resources is revenue. The outflow is expense. Using up the productive capacity of assets in an accounting period is recorded in accounting records as depreciation expense.

The amount of money used to purchase the asset is the basis for the entry in accounting records. This amount is regarded as being definite and immediately determinable. The accounting objectives of verifiability and neutrality are also satisfied. [Emphasis added]

[*Depreciation Expense: A Primer for Utility Regulators*, p. 12]

[408] In 2022, the *Public Utilities Act* was amended to add s. 30(5), which directed the Board to “inquire into and determine the extent, condition and value of the whole or any portion of the property and assets of Nova Scotia Power Incorporated used and useful in furnishing, rendering or supplying a particular service to or for the public”. The Department’s request that the Board exercise its authority to review the value of NS Power’s assets under s. 30(2) of the *Public Utilities Act* would duplicate the proceeding recently completed under s. 30(5).

[409] In 2023, the NSUARB initiated that proceeding and engaged two consultants for this purpose. EA Technology was engaged to review NS Power’s asset management processes and systems, and Doane Grant Thornton (then Grant Thornton) was engaged to review the utility’s accounting policies and procedures with respect to capital assets.

[410] The NSUARB's decision in M11067 (2024 NSUARB 59) outlined how NS Power's property is valued under the *Public Utilities Act*:

[8] Subsection 30(2) of the Act contemplates that the value of NS Power's property and assets is determined on a net book value basis. Specifically, NS Power's property and assets are valued based on their prudent original cost less accrued depreciation. Under s. 30(3) of the Act, depreciation is generally calculated on a straight-line basis.

[9] The net book value of NS Power's property, plant and equipment is reported to the Board annually in the utility's regulated financial statements (e.g., M11090). In Note 1 to its 2022 financial statements in M11090, NS Power set out its accounting policies for "Property, Plant and Equipment":

Property, Plant and Equipment

Property, plant and equipment ("PP&E") are recorded at original cost, including allowance for funds used during construction ("AFUDC") or capitalized interest, net of contributions received in aid of construction.

The cost of additions, including betterments and replacements of units are included in "Property, plant and equipment". When units of regulated PP&E are replaced, renewed or retired, their cost, plus removal or disposal costs, less salvage proceeds, is charged to accumulated depreciation, with no gain or loss reflected in income.

The cost of PP&E represents the original cost of materials, contracted services, direct labour, AFUDC for regulated property or interest for non-regulated property, ARO and overhead attributable to the capital project. Overhead includes costs related to support functions, employee benefits, insurance, procurement, and fleet operating and maintenance.

Normal maintenance projects and major maintenance projects that do not increase the overall life of the related assets are expensed as incurred. When a major maintenance project increases the life or value of the underlying asset, the cost is capitalized.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each functional class of depreciable property. The service lives of assets are determined based on formal depreciation studies and are approved by the UARB. The last depreciation study was completed in 2010.

Intangible assets, which are included in "Property, plant and equipment" consist primarily of land rights and computer software with definite lives. Amortization is determined by the straight-line method, based on the estimated remaining service lives of the assets in each category. The estimated service lives of intangible assets requires regulatory approval.

[M11090, Exhibit N-1, Attachment 2, p. 13]

[411] The Board summarized the two consultants' findings as follows:

EA Technology concluded that NS Power has good processes and systems that identify assets and groups of assets that represent the greatest risk to the organization, but that the processes and systems are typically aimed at the management of NS Power's assets rather than the management of the asset management system. It made several recommendations focused on developing a strategic asset management plan. Grant Thornton concluded, among other findings, that NS Power demonstrated "good utility practice" in its capital approval process, its policies and procedures for asset grouping and depreciation methodologies, as well as asset retirement, disposals, and not used and useful assets.

[Board Decision M11067, p. 2]

[412] The Department (then the Department of Natural Resources and Renewables (NRR)) intervened in the M11067 proceeding and filed submissions on November 29, 2023. It raised no concerns about the longstanding approach to valuing NS Power's assets in that proceeding.

[413] As noted previously, when following the original cost method for valuing the utility's rate base, changes in the estimated lives of the assets over time do not result in write-ups or write-downs of the rate base value. Rather, these are reflected in a step-up or step-down of the depreciation rates used to go forward. Indeed, this was recognized by Christine Runge, Power Advisory, an expert retained by the Department (then NRR) as noted in the NSUARB's decision dealing with the approval of NS Power's DDA (2024 NSUARB 67, paras. 85-88).

[414] If the Board were to consider a departure from the widely recognized and applied original cost-based approach for valuing rate base and depreciation, it would be necessary to take this approach for all classes of property, not simply NS Power's coal assets. In such a case, it is quite possible that the current "value" of many of these assets would vary, upwards and downwards from the net-book value included in rate base. In some cases, the current "value" might even exceed the original cost. The original cost-

based approach ensures that ratepayers pay only the prudently incurred original cost of invested assets (no more, no less) used to provide service.

[415] If there was an overall net reduction in value of the entire rate base because of the change in the valuation method, it does not necessarily follow that the result would be a write-down to be absorbed by the utility. To avoid being confiscatory, and to be consistent with the underlying principle of providing utilities with the opportunity to realize a return of, and on, invested capital, if such a sudden and dramatic change in methodologies were to be made, it is likely a strong argument would exist for creating a reserve or regulatory asset for the transition.

[416] Furthermore, the timing of the change in value would need to be considered. If, for example, the value of the coal assets was not stable, but rapidly declining as 2030 approached, then the rapid decline would need to be reflected in the depreciation claimed in the test years. Depending on the extent of the decline, this could put significant upward pressure on the depreciation expense in the test years, and therefore the revenue requirement and proposed rates.

[417] The complexity and uncertainty associated with this approach would likely warrant a higher return on equity relative to the prudent original cost method.

[418] However, as discussed, this approach has been rejected in most jurisdictions in North America (if not more broadly) as being impractical and inappropriate for valuing a utility's rate base. The rate base value presented in this general rate application follows generally accepted regulatory practice and the default method explicitly referenced in the *Public Utilities Act*. The Board finds it would not be appropriate to depart from this longstanding and recognized approach.

3.6.3.1.2 Assets No Longer “Used and Useful” and the Decarbonization Deferral Account

[419] Referring to “core ideas” from the UAD line of cases and their relevance to Nova Scotia, the Department submitted, “Once an asset is no longer used and useful in providing regulated service, it can be removed from rate base, with associated losses potentially borne by shareholders”. As NS Power noted in its reply submissions, this line of cases was impacted by the recent Alberta Court of Appeal decision in *ATCO Electric Ltd. v Alberta Utilities Commission*, 2023 ABCA 129. This was an appeal from an Alberta Utilities Commission (AUC) decision denying the recovery of assets destroyed in the Fort McMurray wildfire, which it made because it felt it was bound by the earlier decisions.

[420] The Alberta Court of Appeal emphasized that the *Stores Block* decision related only to the sale of assets previously included in rate base and was not directly concerned with setting just and reasonable tariffs for the utility. After reviewing the authorities, the Court stated:

In short, the Commission erred in thinking that these earlier decisions dictated its treatment of assets stranded by unforeseen forces of nature. No binding authority compels relying on the accounting details underlying the predicted survival curves of the asset pools to decide how to deal with assets unexpectedly and permanently removed from active service by forces of nature.

[para. 44]

[421] The Court of Appeal went on to find there was nothing in the relevant legislation that limited the AUC’s discretion over depreciation or stranded assets. The Court summarized its findings as follows:

Summary and Conclusion

[60] To summarize, the issue is where the losses resulting from forces of nature should fall: on the utility’s consumers or on the utility’s shareholders:

- (a) In legal terms the issue is where a just and reasonable tariff would place those losses, having due regard to the right of the utility to a reasonable opportunity to recover its prudent costs.

- (b) This issue was not decided by **Stores Block** or **FortisAlberta**.
- (c) The analysis cannot start with an assumption that it is inherently fair to place the burden on one group or the other. That is the answer, not the premise of the question.
- (d) It is relevant that the utilities stopped buying insurance to save the consumers money. The Commission apparently decided that it was prudent for the consumers to self-insure.
- (e) The answer does not lie in whether the loss was or was not anticipated in the survivor curve behind the depreciation schedules, or whether the loss was therefore ordinary or extraordinary.
- (f) The answer also does not arise from “fundamental property and corporate law principles” or property ownership of the destroyed assets. Loss by fire is not a part of disposition law.

Ultimately the question lies within the discretion of the Commission, to be exercised consistently with the words of the *Electric Utilities Act*, having regard to all relevant considerations, while disregarding irrelevant ones.

[61] In conclusion, the decision under appeal is based on errors of law, particularly the conclusion that the Commission’s options for treating destroyed assets were constrained by **Stores Block**. The setting of rates is clearly within the discretion of the Commission, including the determination of what expenses can be included as recoverable costs and expenses, how to deal with depreciation, and how to deal with stranded or unpredictably destroyed assets. [Emphasis in original]

[422] The Court ultimately returned the matter to the AUC for redetermination following the appropriate principles. In its redetermination, the AUC reversed its earlier decision and allowed ATCO Electric to recover the net book value of the destroyed assets (Decision 28320-D01-2023, December 19, 2023).

[423] The Alberta Court of Appeal’s conclusion in this recent appeal is not dissimilar to findings made by the NSUARB in the recent proceeding about the value of NS Power’s property under s. 30(5) of the *Public Utilities Act*. There, as part of a discussion about the application of NS Power’s Accounting Policy 6350, which deals with assets that are no longer used and useful, the Board discussed the contextual nature of the analysis:

[47] As pointed out in the May 5, 2020, decision letter, Accounting Policy 6350 provides the Board with flexibility, on a case-by-case basis, to address the rate-base treatment of the undepreciated cost when such an application is made. The Board finds that this

flexibility is important and can only be exercised when the full circumstances of the case are known. This could include the reasons why an asset must be retired early, along with NS Power's financial position and the existing regulatory scheme. It could also include the impact of early retirement on rates. These are the two sides of the equation the Board must weigh in the balance.

[2024 NSUARB 59]

[424] When assets need to be retired to meet legislative decarbonization mandates requiring 80% of energy provided to customers be from renewable sources and the phasing out coal-fired generation by 2030, they will no longer be used and useful. However, it must be recognized that the NSUARB previously accepted the use of the DDA as the appropriate method of collecting any remaining net book value of the coal assets when they are retired in accordance with federal and provincial policy.

[425] That decision was made as an alternative to using either Accounting Policy 6350 or adjusting the depreciation rate to recover the undepreciated balance of the assets over their shorter remaining useful life (and the corresponding impact on rates that would have been occasioned as a result). In its decision approving the DDA in principle, the NSUARB noted:

[299] In this context, NS Power is a utility regulated under a cost of service model. This means the Company is allowed to recover its prudently incurred costs in the provision of service to customers and may earn a reasonable return on its related invested capital. Therefore, where the Company has made an investment to the benefit of customers but related prudently incurred costs of capital have yet to be recovered, NS Power may recover these costs even after capital assets have been retired, in circumstances where the assets were retired due to changes in public policy beyond its control. Further, since the costs have yet to be recovered, there are still debt and equity financing costs associated with these investments. None of the parties in this proceeding have suggested that NS Power is not entitled to recover such costs.

...

[310] Based on the above, the Board finds that the proposed DDA provides a mechanism that will allow better flexibility in the recovery of investment in thermal assets that will be phased out due to the decarbonization transition. It will also effectively balance timely recovery of the related costs with customer affordability. The Board also notes that the DDA is not intended to make unrecoverable costs recoverable by NS Power. Instead, it will allow for NS Power's recovery of prudently incurred costs while making the transition to increased renewables to 2030 and beyond more affordable for customers.

[2023 NSUARB 12]

[426] The decision strikes a balance between affordability for customers and the utility's entitlement to an opportunity to recover its prudently incurred costs and a fair return. In making that determination, the NSUARB considered both immediate and long-term impacts on customers. Accelerating the recovery of the net book value and decommissioning costs over the remaining life of these assets would have caused rates to sharply increase, negatively affecting customers. At the same time, holding depreciation rates and forcing NS Power to absorb a significant write-off of the value of the coal assets when they are no longer used and useful could very likely have a material negative financial impact on the financial health of NS Power. As was noted and discussed in the NSUARB's decision in the previous general rate application, negative financial impacts on the utility ultimately cost customers in the form of higher interest costs and reduced ability to raise capital.

[427] This decision was recently mentioned in Deirdre Sheehan et al, *The Push for Electrification and a Net-Zero Grid: Developments, Reactions, and Implications*, 2024 62-2 Alberta Law Review 424, 2024 CanLII Docs 3091:

Consideration of the retirement of coal-fired assets in Nova Scotia by the Nova Scotia Utility and Review Board (NSURB) is illustrative of the potential rate implications of early asset retirement. NS Power expects it will have to retire coal-fired assets and associated infrastructure by 2030 due to its legal decarbonization obligations, prior to fully recovering its investment in these assets or its decommissioning costs in rates. The undepreciated costs associated with these early retirements "may be as much as \$757 million." Seeking approval to accelerate the recovery of depreciation expense (that is, recovery of its remaining capital investment) and decommissioning costs over the years of operation remaining to 2030 "would cause a substantial increase in rates." Therefore, NS Power proposed, and NSURB approved with some changes, the transfer of these costs to a regulatory asset account — the Decarbonization Deferral Account (DDA) — to facilitate rate stability and affordability for customers. NSURB found that the transfer of the costs to the DDA would allow flexibility around the timing of the recovery of the costs, and stated:

To the extent that costs transferred to the DDA are not offset by governments (to recognize the various policy choices reflected in the laws leading to the premature retirement of assets and the broader social benefits from a decarbonized electricity system), they would be recovered from customers over an undetermined future period.

As is evident from the foregoing, absent government funding and in the pursuit of affordability, regulators may need to consider novel and flexible approaches to address the financial impacts of early retirements and other energy transition costs while ensuring utilities have an opportunity to recover the return of and on their investments.

[pp. 453-454]

[428] Confirming the utility's entitlement to recover its undepreciated costs through the DDA is consistent with longstanding Canadian regulatory principles and practices, including those described in the recent Alberta Court of Appeal decision. The NSUARB determined that the DDA was the most appropriate approach in the circumstances presented by the need to transition to decarbonized energy systems, consistent with federal and provincial government policies and legislation. There is no basis to revisit that decision.

3.6.3.1.3 The Requirement for Prudence

[429] Prudence is, of course, always a consideration. The language used in s. 30(2) of the *Public Utilities Act* is not simply "original cost" but "prudent original cost". A utility is entitled to the opportunity to recover its prudently incurred costs. That is, costs incurred under a standard of care that a reasonable person would expect to be made by other similarly situated utilities in the same circumstances encountered by the utility at the time decisions had to be made.

[430] The Board's approach to prudence was recently canvassed in its decision in NS Power's most recent fuel adjustment mechanism audit (2025 NSEB 10, paras. 17-49). Useful principles were helpfully outlined by the Industrial Group in its submissions in that matter, which were referenced in the decision:

[18] The Industrial Group's closing submissions in this proceeding listed the following principles about the prudence of utility expenses, which it extracted from the legislation and case law:

1. The Board may allow the utility's expenses which are "reasonable and prudent and properly chargeable."

2. NSPI benefits from an initial presumption that its decisions are prudent.
3. The presumption of prudence is rebutted when questions are raised. This is the first stage. Hindsight may be used at this stage.
4. When prudence has been called into question, NSPI must discharge its burden to satisfy the Board that it applied a reasonable standard of care in its decision-making and actions, and that its expenses were reasonable and prudent based on information known or ought to have been known at the time. This is the second stage. Hindsight may not be used at this stage.
5. If a finding of imprudence is made, the Board may disallow costs which have been imprudently incurred. [Footnotes omitted]

[Industrial Group, Closing Submissions, pp. 2-3]

[19] The Board finds this to be a helpful summary. In this case, there did not appear to be significant disagreement over these principles (except for the use of hindsight to rebut the presumption of prudence). There was considerable disagreement about how these principles applied in the context of a FAM Audit. Positions differed on the threshold for rebutting the presumption of prudence. The parties also debated when human error might amount to imprudence.

[431] The Board went on to find:

[42] In summary, the Board finds that the threshold for rebutting the presumption of prudence is contextual. It requires a reasonable question – something that is more than a bald statement or speculation – but it should not be too onerous and may arise in hindsight. In the context of a FAM Audit, the audit report may provide context but does not increase the threshold for rebutting the presumption or reverse the onus. Questions raised in the FAM Audit may rebut the presumption of prudence. The audit report is also available as evidence to assess the ultimate issue of prudence (although hindsight may not be used in this stage of the assessment).

[432] In its closing submissions in the current matter, the Department suggests two areas where NS Power's prudence may be questioned. The first is that depreciation rates were too low, resulting in present net book values for retiring coal assets to be recovered from customers that are higher than they should have been. The second, is that NS Power unnecessarily invested in these assets in the face of impending retirements.

[433] As discussed previously in this decision, the last depreciation study presented to the regulator before the one in this proceeding was filed with the NSUARB in 2010. The depreciation rates NS Power originally sought in that application were higher

than those eventually accepted by the NSUARB. These were reduced in a “black box” settlement following the filing of evidence by experts suggesting they were too high and that some asset lives were too short. In its closing submissions, the Department recognized that the impact of the settlement agreement in Matter M03665 kept customer rates lower in the near term. As that proceeding was not a general rate application, the depreciation rates could not be immediately implemented. They were implemented in NS Power’s next general rate application, which was filed in 2011, and a decision was rendered in December 2012. The decision in that matter also accepted a settlement agreement signed by a number of intervenors.

[434] NS Power’s next general rate application was filed in January 2022. In that matter, NS Power failed to file an updated depreciation study, as the Board would have expected, but NS Power recognized that the requirement to close coal plants by 2030 challenged the recovery of undepreciated costs relating to those assets and proposed the DDA, as discussed previously in this decision.

[435] A subsequent proceeding to formally approve the DDA was initiated by NS Power. Several parties in that proceeding argued that the costs to be transferred into the DDA should be reviewed. However, none of them, including the Department (then NRR) who retained an expert to file evidence in that proceeding, suggested that the amount should be reduced because of imprudently charged depreciation rates.

[436] Regarding the issue of improper investment in the face of impending coal plant closures, the Department’s expert in the DDA matter supported NS Power’s recovery of the cost of the coal generation assets but recommended that NS Power be

allowed to recover the unamortized balances of the coal assets only where the Board has determined those costs have been prudently incurred:

[57] Ms. Runge supports NS Power's recovery of its prudently incurred investments in its coal generation assets:

75. The no hindsight principle should always be applied in the assessment of the return of capital to a utility. If the investment was considered prudent at the time it was made with all reasonably available knowledge applied to that assessment, then the utility should not be at risk for the recovery of those costs.

76. The end goal of the regulatory compact is to be fair to both the utility and the rate payers, where one party has an obligation to serve and minimum reliability standards to uphold and the other is held captive given inelastic consumer demand and monopoly utility supply. Application of the no hindsight principle to return of capital is fair to both parties. The coal generation assets were built for rate payers. At the time they were built, they were considered to be prudent. Rate payers wanted access to cost-effective electricity, which was provided to them, and NSPI had an expectation that in exchange for building long-life assets to provide that electricity, it would recover those prudently invested costs over the life of the assets.

77. Consistent application of the no hindsight principle to the return of capital also benefits both parties over the long run. The utility benefits from certainty of cost recovery associated with investment choices that were considered prudent at the time they were made, with no risk that costs will later be removed from rate base due to changes in government policy or technological advancements that occur. At the same time, rate payers benefit as the result is significantly lower utility risk than the application of the used and useful principle to the return of capital, which allows for a lower ROE and potentially a lower cost of debt than would be the case under a policy focused on the used and useful test. In the long run, the application of a lower ROE to the totality of a utility's rate base can be more beneficial to rate payers than small costs that may otherwise be removed from rate base from time to time due to early retirements.

[Exhibit N-10, p. 23]

[58] She goes on to say that this only applies to costs determined to have been prudently incurred. It notes that not all costs incurred by NS Power are subject to an explicit prudence review when they are incurred and highlights the importance of such reviews to ensure that the utility is making only proper investments and not adding to its rate base to inappropriately increase its return:

79. The prudence test is an important part of the regulatory compact. Due to the fact that a utility is a natural monopoly provider of service, if the utility established its own pricing in the absence of a regulator, the utility would have the ability to charge rates that include significant rents as a result of its market power in the region and high consumer demand for its product. Regulatory proceedings that test the proposed investments of a utility allow for rates that are more reflective of competitive market pricing instead of this monopolistic pricing. Given that the ROE is established in a

regulatory proceeding and that in the case of NSPI there is no ability to earn above the approved ROE by more than 0.25%, the means by which NSPI increases its profitability is to invest in capital and increase its rate base. Accordingly, the utility has an incentive to over-invest in capital if it can get those costs approved and added to rate base. Continued testing of costs to ensure prudence of investments is, therefore, required in order to ensure just and reasonable rates.

[Exhibit N-10, p. 24]

[59] Ms. Runge recommends that NS Power be allowed to fully recover the unamortized balances associated with the early retirement of its coal assets where the Board has determined those costs to have been prudently incurred. However, she submitted that, before adding them to the DDA, the Board should evaluate the prudence of any costs NS Power proposes to transfer to the DDA that have not already been found by the Board to have been prudently incurred. Ms. Runge said NS Power should apply to the Board for this purpose when it wants to add such costs to the DDA. [Emphasis added]

[2024 NSUARB 67]

[437] In its decision, the NSUARB referenced the general principles it applied to prudence questions, noting the general presumption of prudence and that it was open for parties to raise questions of imprudence. In respect of the concern about sustaining capital, the NSUARB noted:

[72] Some parties expressed concerns about future sustaining capital and decommissioning costs. Costs of this nature may exceed the \$1,000,000 threshold, providing parties with an opportunity to question their legitimacy in future capital approval applications, before they are incurred. The Board expects these concerns will be advanced and assessed in the context of the applications for these specific investments. To ensure that the Board's processes appropriately allow for such participation, particularly if the requested capital approval is not included in an approval requested in an ACE plan proceeding, the Board directs NS Power to provide specific notice to all participants in this proceeding upon filing any future capital work order applications involving assets that are forecasted to be included in the DDA and to confirm this was done in its applications to the Board.

[73] The Board also notes that NS Power said the Board may choose to review costs transferred to the DDA in any given year:

... The reporting requirements outlined in the DDA Manual are intended to provide all stakeholders with transparency around transfers to or from the DDA in any given year and the Board may choose to review any of these transfers.

[NS Power Reply to Closing Submissions, p. 5]

[74] Based on this, it is possible that circumstances may arise that make it appropriate to consider the prudence of costs transferred at that time. However, as noted above, the Board has found that making the transfer of costs to the DDA dependent on mandatory applications to determine their prudence (where this has not already been determined) is not consistent with the capital approval provisions in the *Public Utilities Act*. Likewise, NS Power should understand that the Board's acceptance of any DDA reports filed following

the processes outlined in the proposed DDA Manual would also not constitute a finding that the costs included in the report were prudent.

[2024 NSUARB 67]

[438] In short, it remains open for the Department or other parties to challenge the prudence of any of NS Power's expenditures, but these are presumed prudent and there is a threshold that must be met to rebut this presumption. The Department filed no evidence in the current GRA proceeding, did not explore questions of prudence in any cross-examination, and only raised these issues in closing submissions. Additionally, the allegation of imprudent investment was only raised in a very general way. While the issue about depreciation rates was somewhat more specific, it was still quite general and also failed to address the impact of the equivalency agreements between the Province of Nova Scotia and the Government of Canada. Therefore, the Board finds that the threshold for rebutting the presumption of prudence has not been met in this proceeding.

3.6.4 Findings

[439] The Board accepts NS Power's forecasted average rate base of \$5.58 billion in 2026 and \$5.89 billion in 2027.

3.7 Return on Equity and Capital Structure

[440] NS Power's existing rates are set based on a current capital structure that includes 40% equity and 60% debt, with an approved return on equity of 9%. Under the current framework, NS Power may realize an annual return on equity up to 9.25% and must return any earnings above 9.25% to its customers.

[441] In this proceeding, NS Power proposed to continue to set rates based on a 9% return on equity within a range from 8.75% to 9.25%. NS Power also requested to maintain its debt-to-equity ratio, for rate-setting purposes.

3.7.1 The Fair Return Requirement

[442] NS Power operates as a natural monopoly in Nova Scotia, where the absence of meaningful competition means the competitive forces of the market do not apply. Section 45 of the *Public Utilities Act* entitles a public utility to earn a just and reasonable return on its rate base, in addition to recovering its reasonable operating expenses and other just allowances. As a result, it is the Board's responsibility to set the parameters under which the utility may earn a return from its customers.

[443] A fair return is fundamental to ensuring the utility's ongoing financial stability. Because NS Power must secure external 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, which could affect NS Power's access to capital on reasonable terms and could place downward pressure on its credit rating. A weak credit rating increases borrowing costs and, therefore, raises the costs paid by customers. The company could even lose access to certain debt markets altogether, with more significant cost implications for NS Power and its customers.

[444] There is a well-recognized and long-standing legal standard the Board must follow when approving a utility's return on its invested capital. A century ago, the Supreme Court of Canada described the test as follows:

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. ... [Emphasis added]

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

[445] This test was more recently accepted by the Supreme Court of Canada in *Ontario (Energy Board) v Ontario Power Generation Inc.*, 2015 SCC 44:

15 This Court has had the occasion to consider the meaning of similar statutory language in *Edmonton (City) v. Northwestern Utilities Ltd.*, [1929] S.C.R. 186 (S.C.C.). In that case, the Court held that "fair and reasonable" rates were those "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" (pp. 192-93).

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]

[446] The latter part of this passage endorsed the Federal Court of Appeal's comments in *TransCanada Pipelines Ltd. v Canada (National Energy Board)*, 2004 FCA 149, where that court said:

12 Even though cost of capital may be more difficult to estimate than some other costs, it is a real cost that the utility must be able to recover through its revenues. If the Board does not permit the utility to recover its cost of capital, the utility will be unable to raise new capital or engage in refinancing as it will be unable to offer investors the same rate of return as other investments of similar risk. As well, existing shareholders will insist that retained earnings not be reinvested in the utility.

13 In the long run, unless a regulated enterprise is allowed to earn its cost of capital, both debt and equity, it will be unable to expand its operations or even maintain existing ones. Eventually, it will go out of business. This will harm not only its shareholders, but also the customers it will no longer be able to service. The impact on customers and ultimately consumers will be even more significant where there is insufficient competition in the market to provide adequate alternative service. [Emphasis added]

[447] The Federal Court of Appeal also addressed a concern raised by TransCanada Pipelines that the National Energy Board set its return on equity too low because it improperly considered the impact that higher rates would have on TransCanada's customers. Although the court found the evidence did not support the conclusion that the National Energy Board had suppressed the return on equity because

of the resulting impact on customers, it accepted the impact of the return on customers was not a relevant factor under the *Northwestern Utilities* test:

35 In oral argument, the appellant conceded that it does not object to its customers having input into the Board's cost determinations and in particular, its cost of capital determination, provided the issues in dispute are restricted to the costs of the Mainline. However, the appellant does object to the Board taking the impact of tolls on customers and consumers into account in determining the Mainline's cost of equity capital. The appellant says that the required rate of return on equity must be determined solely on the basis of the Mainline's cost of equity capital. The impact of any resulting toll increases on customers or consumers is an irrelevant consideration in that determination. The appellant does concede that when the final tolls are being fixed, the impact on the customers and consumers may be relevant, but insists that it is irrelevant when determining the required return on equity.

36 I think that this argument is sound and in keeping with the decision of the Supreme Court in *Northwestern Utilities*. The cost of equity capital does not change because allowing the Mainline to recover it would cause an increase in tolls. Under the Board's Equity risk premium methodology, the cost of equity capital is driven by the Board's estimate of the risk-free interest rate and the degree of risk investors perceive in the "benchmark" pipeline. The higher the risk, the higher their required rate of return. The degree of risk specific to the Mainline is accounted for by adjustments to its deemed capital structure. Accordingly, the cost to the Mainline of providing that rate of return on the equity component of its deemed capital structure is unaffected by the impact of tolls on customers or consumers.
[Emphasis added]

[448] The Federal Court of Appeal went on to say that although the impact on customers cannot be a factor in determining the utility's entitlement to a specific return on equity, any resulting increase in tolls may be a factor in determining the way the utility may be able to recover its costs. In particular, the court said if an increase would be so significant it would lead to "rate shock" if implemented all at once, rate increases could be phased in over time, "provided that there is, over a reasonable period of time, no economic loss to the utility in the process. In other words, the phased in tolls would have to compensate the utility for deferring recovery of its cost of capital" (para. 43).

[449] In a similar vein, a recent Ontario Energy Board decision noted that ensuring the utility has the necessary financing to carry out its operations must be the focus when setting a return on equity. The setting of the return on equity is not a tool to "balance" competing interests between the utility and its customers:

The OEB affirms that in setting this important component of the determination of the cost of capital for regulated utilities it adopts the requirements of the [fair return standard], as set out in the 2009 Report. These requirements mandate a regulatory return that meets the market expectations derived from the review of comparable investments, ensures the financial integrity of the subject utilities and allows for compliance with the capital attraction standard: the approved return must permit incremental capital to be attracted to the enterprise on reasonable terms and conditions. The [fair return standard] does not involve the balancing of interests between the utility and its customers but is singularly focused on ensuring that a utility is furnished with the necessary financing to carry out its responsibilities of service to its customers. However, the utility is allowed the opportunity to earn its cost of capital, no more and no less. [Footnotes omitted] [Emphasis added]

[OEB EB-2024-0063, p. 34]

[450] In *Energy Law and Policy* (Kaiser and Heggie, ed., 2011), Canadian authors, Gordon Kaiser and Bob Heggie, summarized the principles considered by regulators to set fair returns:

While no legislative guidance is provided as to what a regulator is to take into account in determining a fair return, United States and Canadian courts have considered the issue. The courts have listed factors that tribunals should consider, but have not prescribed methods for calculating a fair return. To be considered fair, tribunals have taken the following principles or standards into account in determining returns:

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

The comparable investment principle is based on the idea that in order to be fair to a utility equity investor, the investor must be satisfied that the potential return on the investment is sufficient to compensate for the risk assumed in relation to the entire spectrum of comparable competitive investments available. The challenge with this principle is finding comparable companies with similar risks.

The financial integrity and capital attraction principles are more straightforward and generally will be satisfied if the comparable investment principle is met. Financial integrity is satisfied if the combined effect of the allowed return and the equity thickness of a utility's capital structure results in a debt coverage ratio sufficient to support stable investment grade ratings.

Debt investors need earnings to provide security for the debt capital invested. The difficulty with this principle is determining whether a particular desired rating should drive the allowed return.

Capital attraction means that returns must be adequate to attract necessary capital on reasonable terms to build required utility infrastructure.

[Energy Law and Policy, pp. 188-189]

[451] Similar principles are considered by utility regulators in the United States: *Bluefield Waterworks & Improvements Co. v Public Service Commission of West Virginia* (1923), 262 US 679 (US W. Va.) and *Federal Power Commission v Hope Natural Gas Co.* (1944), 320 US 591 (US Sup Ct.). In *Re Nova Scotia Power Inc.*, 2019 NSUARB 165, the NSUARB referenced *Northwestern Utilities*, *Bluefield* and *Hope* as “landmark decisions which set out general principles with respect to rate of return”.

[452] The assessment of these principles in any matter before the Board is based on the evidence presented. In the current case, due to NS Power and customer representatives reaching a consensus agreement in advance of the general rate application, only two parties presented the Board with expert evidence, NS Power and Board Counsel.

3.7.2 Overview of Cost of Capital Evidence

3.7.2.1 Return on Equity

[453] Determining a fair return on equity generally entails the use of several well-established financial models. These include, but are not limited to, the discounted cash flow (DCF) model; the capital asset pricing model (CAPM) and the risk premium model. In practice, common approaches assess prevailing conditions in the capital markets and often validate conclusions through the application of multiple models to ensure consistency and robustness.

[454] Under the consensus agreement, the signatories agreed to a return on equity for NS Power of 9% for rate setting purposes, with an earnings band of 8.75% to

9.25%. They also agreed that an equity thickness of 40% for rate setting purposes would be retained.

[455] NS Power presented evidence from its cost of capital expert witnesses James Coyne and John Trogonoski of Concentric Energy Advisors (Concentric). Concentric reviewed the economic and financial market conditions in Canada and the United States (U.S.) to inform how those conditions affect a utility's return on equity. Concentric noted that the risk to a company's earnings is a function of its business and financial risk. Utilities obtain debt and equity in capital markets that are affected by macroeconomic indicators and central bank policies. Concentric's evidence filed with NS Power's application used market data as recent as February 2025.

[456] Concentric believes that since the interest rates on government and utility bonds have been stable since NS Power's last GRA, the cost of utility capital has been stable. However, over the long-term, Concentric expects the electric utility industry to experience structural challenges associated with climate change, cybersecurity, grid improvements and customer preferences. Therefore, Concentric says NS Power requires a return on equity that is competitive enough to attract the investment it will need to support its own energy transition.

[457] To determine a suitable return on equity for NS Power, Concentric created proxy groups of companies it considered to be comparable to NS Power in terms of business and financial characteristics. Concentric regards the nature of the financial markets in the U.S. and Canada as integrated and utility regulatory systems as similar. In total, Concentric created 3 proxy groups: a group of 5 Canadian electric utilities; a group of 10 U.S. electric utilities; and a North American group consisting of 10 U.S. proxies and

3 Canadian proxies. Its return on equity recommendations are based on its North American proxy group.

[458] Based on the average return on equity results from its DCF, CAPM and risk premium models, Concentric recommended a return on equity for NS Power of 9.9%. This is higher than the return on equity proposed under the settlement agreement, but Concentric believes this to be a reasonable return on equity for NS Power. Concentric's recommendation incorporated an adjustment for flotation costs and financing flexibility of +50 basis points, or +0.5%. Concentric made this adjustment in its DCF and CAPM models to reflect costs associated with the sale of new issues of common equity.

[459] Concentric evaluated NS Power's return on equity using current and forecast economic conditions for Canada and the United States. However, it conducted its analysis early in 2025, a year in which tariff threats and uncertainties escalated globally with geopolitical tensions testing longstanding trade relationships leading to market turmoil and repeated changes to economists' forecasts. As NS Power did not file its application until September of 2025 and the hearing was held in January 2026, some of the information used in Concentric's analysis was stale.

[460] In response to Undertaking U-14 [Exhibit N-81], Concentric updated its return on equity analysis using market data as of December 31, 2025. Based on this data, the average return on equity of the three models for Concentric's North American proxy group fell from 9.90% to 9.43%. NS Power suggested this result was due to a significant drop in utility beta values during 2025, along with a smaller reduction in Canada's forecasted GDP growth. Higher forecasted long-term government bond yields partially offset these effects.

[461] Board Counsel consultant, Dr. Cleary, was the only expert witness to provide an alternative cost of capital review. Dr. Cleary presented evidence that equity returns allowed by regulators in Canada and the U.S. have not declined in the past two decades. He believes, however, that these returns should have declined, with reductions in government and utility bond yields. He also believes that Canadian and U.S. utilities are earning excess compensation relative to their actual market-determined cost of equity. He highlighted that there is general market acceptance that utility companies are less risky than the average publicly traded company, which implies expected returns should be less than that of an average risk company.

[462] Dr. Cleary reviewed the economic and financial market conditions in Canada and the U.S., but he focused his analysis on Canadian data and forecasts. Dr. Cleary argued against using U.S. utilities as proxies for NS Power because he does not consider them to be reasonable comparators for Canadian utilities. He argued, in part, that U.S. utilities are higher risk than Canadian utilities because they are typically holding companies, they operate in the U.S. and the nature of their operations entails more risk. He did not agree that Concentric's North American proxy group was an appropriate comparator group for NS Power because he viewed the U.S. companies that made up most of this proxy group as having significantly higher average risk.

[463] Dr. Cleary supported his position that U.S. utilities were, on average, riskier than Canadian utilities with an examination of utility betas. Betas measure the volatility of a company's stock compared to the overall return in the market. He said this analysis demonstrated that, over a lengthy period, U.S. utility betas are much higher than Canadian utility betas.

[464] NSP Maritime Link's 2026 annual assessment (Matter M12394) included evidence provided by Dr. Cleary and Concentric that was similar to what they filed in this proceeding. During his testimony in that matter, Dr. Cleary also explained that Canadian institutional and fixed income investors exhibit a home-country bias, influenced in part by comparatively higher U.S. payout structures and exposure to foreign exchange risk.

[465] Dr. Cleary further noted that, following the 2024 U.S. Presidential election, economic and political developments have contributed to a divergence in the previously aligned economic relationship between the U.S. and Canada, with the potential to become more disconnected.

[466] Dr. Cleary recommended a 7.6% return on equity for NS Power based on his financial modeling using CAPM, DCF and risk premium models. Like Concentric, he included an adjustment for flotation costs of 50 basis points or 0.5%.

[467] A summary of the results derived from Concentric's and Dr. Cleary's return on equity evidence is set out in the table below, with the numbers for Concentric taken from its response to Undertaking U-14:

Summary of Return on Equity Results				
	CAPM	DCF	Risk Premium	Opinion
Concentric	9.23%	9.02%	10.04%	9.43%
Cleary	6.84%	7.86%	7.94%	7.6%

3.7.2.2 Capital Structure (Equity Ratios)

[468] Concentric determined that a common equity ratio of 45% would be appropriate for NS Power. Concentric considers the requested common equity ratio of 40% (per the settlement agreement) to be conservative given NS Power's financial and business risks from owning generation assets and a requirement to accelerate the retirement of much of its thermal generation by 2030. NS Power's request to maintain its

40% equity ratio leaves it similarly situated to other Canadian utilities but lower than American integrated electric utilities, based on Concentric’s comparison of equity ratios of other electric utilities (reproduced below):

Figure 30: Authorized Electric ROEs and Equity Ratios

	Generation	ROE	Equity Ratio
NSPI (existing)	Yes	9.00%	40.0%
NSPI (Concentric analysis)	Yes	9.90%	45.0%
NSPI (proposed)	Yes	9.00%	40.0%
Newfoundland Power	Minimal	8.60%	45.0%
Maritime Electric Company Ltd	Minimal	9.35%	40.0%
Ontario Electric Utilities	None	9.00%	40.0%
Alberta Electric Utilities	None	8.97%	37.0%
FortisBC Inc.	Yes	9.65%	41.0%
Canadian Electric Average		9.11%	40.6%
U.S. Electric Utilities ⁵⁹	Yes	9.79%	52.0%
U.S. Electric Proxy Group Average ⁶⁰	Yes	9.66%	51.1%

[Exhibit N-8, Appendix 10A, p. 57 of 87]

[469] Dr. Cleary supported NS Power’s requested 40% equity ratio, stating it is reasonable given its lower debt rating of BBB- and because NS Power holds a higher percentage of generation assets compared to other Canadian utilities.

3.7.3 Return on Equity Modeling

[470] In the discussion that follows, references to results from Concentric’s analysis are to the update it provided in Undertaking U-14 using the analysis as generally described in its original report [Exhibit N-8, Appendix 10A] for its North American proxy group.

3.7.3.1 CAPM Models

[471] The CAPM accounts for the risk of common equity relative to risk free securities such as government bonds. The CAPM model estimates the required return of a security based on the relationship between the expected return of the market and the

systematic risk of the security. The main components of the CAPM model include the risk-free rate of return, the market risk premium and company betas.

[472] The market risk premium is measured as the difference between the expected return of the market and the risk-free rate. It represents the rate of return over and above the risk-free rate. The expected return of the market is a long-term assumption about how the market will perform over time. The risk-free rate is typically represented by the long-term government bond rate. As discussed previously, beta is a measure of a stock's risk and is measured by the changes in its price relative to changes in the overall market.

[473] Based on its assessment of its North American proxy group and adjusting for flotation costs, Concentric determined that a return on equity of 9.23% was appropriate under its CAPM analysis. Dr. Cleary estimates a 6.84% return on equity under his CAPM assessment, with adjustments.

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[474] A summary of the formula components used by Concentric and Dr. Cleary is set out in the table below:

	CAPM	
	Concentric	Cleary
Risk-free Rate	3.87% (Canada) 4.56% (U.S.) <i>[Average long-term Consensus Forecast of 10-year government bond yields plus the average spread between 10- and 30-year bond]</i>	3.66% <i>[Long-term government yield of 3.66% as of November 20, 2025]</i>
Market Risk Premium	5.75% (Canada) 7.31% (U.S.) 6.53% (Average) <i>[Kroll]</i>	5.5% <i>[Within historical range of 4-6%]</i>
Beta	0.66 (mean) <i>[Bloomberg and Value Line]</i>	0.45 <i>[Usual point within historical range of 0.30-0.60]</i>
Average Yield Spread Adjustment		-0.15%
Debt Cost Spread		0.35%
Financial Flexibility	0.50%	0.50%
ROE	9.23%	6.84%

[475] For the risk-free rate of return, Concentric uses *Consensus Economics* forecasted 10-year government bond yield plus the average ten-year historical spread between the 10-year and 30-year government bonds (Canada, 3.87%; U.S., 4.56%). Dr. Cleary estimates CAPM using the actual yield on long-term government bonds at a recent point in time for his risk-free rate. In this case, he used the long-term government yield of 3.66% as of November 20, 2025.

[476] Concentric's risk-free rates are higher, particularly for the U.S. In his evidence, Dr. Cleary argued that using Consensus yield forecasts as a proxy for future 30-year Canada yields has led to an upward bias relative to the subsequent actual yields that prevail. Dr. Cleary also criticized Concentric's derivation of 30-year bond yields. The

use of spreads to adjust 10-year bond yields to 30-year bond yields introduces further assumptions and sources for error.

[477] Concentric estimated the historical market risk premium based on the arithmetic mean of the equity market returns for large company stocks minus the income only return (i.e., the bond coupon rate) on long-term government bonds using data from Kroll, LLC. The market risk premium for Canada is based on returns from 1919-2023 (5.75%) and, for the U.S., on returns from 1926-2023 (7.31%).

[478] Concentric averaged the market risk premiums for Canada and the U.S. (6.53%) and applied the average to all proxies, irrespective of the country. Concentric regarded the market risk premiums in Canada and the U.S. as highly correlated, although there was significant disagreement from Dr. Cleary throughout his evidence about the inclusion of U.S. proxies.

[479] Dr. Cleary suggests that market risk premiums lie within a “commonly used 4-6% range”. He cites academic studies to support this view. Dr. Cleary notes that A-rated Canadian utility bond yield spreads were well below their long-term average, indicating a low-risk environment that would normally lead him to use a market risk premium of 4.5% or 5%. However, citing uncertainties due to global trade tensions, which pose a risk to future economic growth, he settled on a market risk premium of 5.5%.

[480] Concentric’s market risk premium is higher than Dr. Cleary’s. Dr. Cleary attributed this to the use of U.S. data. He also noted that Concentric’s market risk premium estimates use income only returns for bonds rather than total returns, which neglects to account for both the interest and capital gains (or losses).

[481] Concentric sourced adjusted betas from Value Line and Bloomberg. These are raw betas that have been adjusted on the theory that there is a tendency for betas to revert towards the market mean of 1.0 over time and a need to account for errors associated with statistical estimates. Concentric's position is that raw betas are inferior inputs because they do not represent the expected returns or the average market returns. It said that the CAPM is a forward-looking model, therefore a forecasted beta and its tendency to perform at the average of the market over time is not limited by the historical performance of the industry beta.

[482] Dr. Cleary reviewed beta estimates in his evidence and arrived at several conclusions about appropriate beta estimates. Based on his assessment of research conducted in other cases and academic study, Dr. Cleary says that U.S. utility beta estimates are higher than those for Canadian utilities and should not be used. He submits that Canadian utility beta estimates have historically averaged between 0.2 and 0.4 (with 0.35 being the "best estimate"). He said Canadian utility beta estimates have never come close to 1.0, with maximum values being in the 0.6-0.8 range; therefore, he considered the use of "traditional adjusted betas to be totally inappropriate". He submitted that, based on historical evidence, a range of reasonable estimates for betas was between 0.3 and 0.6.

[483] Dr. Cleary noted that he has used a beta of 0.45 "in several previous utility proceedings" and that is his assessment in this proceeding as well. Although Dr. Cleary noted that beta estimates for companies can change dramatically through time, he said this demonstrated why it was appropriate to reference long-term averages and use judgement to determine the best estimates of future betas.

[484] As with the other parameters in the model, Concentric's beta estimate was higher than Dr. Cleary's. While Dr. Cleary applied his "usual" 0.45 beta, Concentric used company specific adjusted betas from Bloomberg and Value Line. These varied, but all were above Dr. Cleary's estimate. Of note, the Canadian companies in his North American proxy group had the lowest values. The mean value of all betas in the proxy group was 0.66, somewhat above Dr. Cleary's range of reasonable estimates.

[485] In addition to the adjustment for flotation costs and financing flexibility that both he and Concentric made, Dr. Cleary made other adjustments. First, he explained that government bond yields have increased recently but are still low. He said A-rated Canadian utility bond yield spreads have increased but are less than the long-term average spread. He noted that the Bank of Canada indicated that the increased spread is due to liquidity problems, but some of it still reflects increased risk premiums for low-risk firms, like utilities. He made a downward adjustment of -0.15% to account for the time varying risk premium. Second, Dr. Cleary also remarked that NS Power is paying 0.35% more on its long-term debt than the average Canadian utility. He applied this spread to adjust his CAPM estimates upward.

3.7.3.2 DCF Models

[486] The DCF model infers the required rate of return by replicating the actions of an investor in valuing the firm's securities by estimating the dividend yield and future growth rate.

[487] Based on its assessment of its North American proxy group and adjusting for flotation costs, Concentric determined that a return on equity of 9.02% was appropriate under its DCF analysis. Dr. Cleary estimated a 7.86% return on equity under his DCF (DDM) assessment, with adjustments.

[488] A summary of the formula components used by Concentric and Dr. Cleary is set out in the table below:

	DCF	
	Concentric	Cleary
Dividend Yield	3.49% <i>[Calculated from Bloomberg]</i>	5.29% <i>[Calculated from Morningstar]</i>
Multi-Stage Growth Rate Years 1-5	6.62% (Mean) <i>[Zacks, SNL Financial, Value Line, Seeking Alpha]</i>	
Multi-Stage GDP Growth (perpetuity)	3.84% (Canada) 4.24% (U.S.) <i>[Consensus Economics]</i>	
DDM Sustainable Growth Rate		1.64% <i>[Calculated from Morningstar]</i>
Debt Cost Spread		0.35%
Financial Flexibility	0.50%	0.50%
ROE	9.02%	7.86%

[489] Concentric's multi-stage DCF model uses three phases of growth: near-term, reflecting the initial 5-year period; transitional growth, years 6 to 10; and long-term growth, years 11 and beyond. The near-term growth rates are based on analysts' earnings per share growth forecasts for each company in the proxy group (6.62% (mean)). Concentric's long-term growth rates are based on forecasted real GDP growth plus inflation (Canada, 3.84%; U.S., 4.24%). The medium term or transitional growth rates are pro-rated in a linear fashion.

[490] Dr. Cleary expressed concerns about Concentric's DCF model, noting its reliance on short-term earnings per share growth based on sell-side analysts' forecasts, rather than buy-side. He observed that the sell-side forecasts are typically upwardly biased and exceed nominal GDP growth rates as used in the final stage of the model. He

further stated in his evidence that using nominal GDP as a long-term growth assumption is overly optimistic for a low-risk utility, and that Concentric's model effectively assumes dividend growth above GDP for 10 years, before converging to nominal GDP thereafter.

[491] In its report, Concentric anticipated these criticisms. Concentric emphasized its use of multiple sources of earnings growth, which it says best informs the overall estimate, enhances its model and reduces the chance for arbitrary adjustments and custom calculations. Based on an historical analysis, Concentric submitted that both earnings and dividend growth have exceeded GDP growth, so analyst growth estimates should not be presumed to be upwardly biased just because they are higher than GDP growth.

[492] Using dividend yields for the companies in the proxy group (3.49% (mean)), Concentric's result was a return on equity of 9.02% after flotation costs.

[493] Dr. Cleary applied a Dividend Discount Model (DDM), which is a variation of the constant growth DCF model that assumes the market price of a stock is equal to the present value of expected future cash flows (dividends paid per share) that equity holders expect to receive. To begin his analysis, Dr. Cleary calculated the implied rate of return for the overall market and then applied the model at the industry level using values he considered to be representative of publicly traded utilities in Canada.

[494] To determine the overall return for the market in his DDM model, he uses the average real GDP growth rate from 1992 to 2024 and various estimates of forecasted GDP growth rates in 2025 and 2026. He then adds the target inflation rate to arrive at a nominal GDP estimate (3.8%). Dr. Cleary then inputs the dividend yield for the S&P/TSX

as of December 31, 2024, (2.83%) to derive an implied equity return for the market as a whole for 2024 (6.74%).

[495] Dr. Cleary notes that a limitation of the single-stage growth model he uses is the assumption of constant growth in dividends to infinity. He said this limitation may be overcome by using a multi-stage version of the DDM called the H-Model, which assumes that growth in dividends moves in linear fashion from some current short-term growth rate toward some long-term growth rate over a specified period of time. Applying this model, he uses the 2025-2026 nominal growth rate for the short term (3.2%) and the average nominal GDP growth rate from 1992 to 2024 (4.3%) to derive a market return of 7.19%.

[496] Dr. Cleary then applies his DCF (DDM) model to sample Canadian utilities using each company's sustainable growth rate by multiplying the earnings retention ratio by return on equity. He explained that growth in earnings is positively correlated to the amount of earnings reinvested and then multiplied by the return earned on those reinvested funds, measured using return on equity. Dr. Cleary noted that it is difficult to find representative Canadian regulated public-traded utilities. He applies averages and medians of historical data to arrive at an estimate of sustainable growth rates. Using an estimated sustainable growth rate of 1.64% produced an implied return of 7.01%.

[497] Due to a negative average return on equity in his dataset, and what he considered to be abnormally high payout ratios in 2024, Dr. Cleary did not apply his H-Model to his Canadian utilities sample. However, he compared the results to his results for the overall market. Adjusting for cost of debt and flotation costs, Dr. Cleary calculated a required return of 7.86% using this approach.

3.7.3.3 Risk Premium Model

[498] The risk premium model can be based on 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 the equity investors bear the residual risk associated with ownership and therefore require 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 return on equity as the sum of the yield on long-term bonds and the equity risk premium.

[499] Both Concentric and Dr. Cleary used the risk premium model, but they did so in entirely different ways. A summary of the formula components used by Concentric and Dr. Cleary is set out in the table below:

	Risk Premium	
	Concentric	Cleary
A-rated Utility Bond Yield (Nova Scotia Power)		4.94% [Bloomberg]
Government Bond Yield (Canada)	3.82% (average) [Calculated from Bloomberg and Average long-term Consensus Forecast of 10-year government bond yields plus the average spread between 10- and 30-year bond]	
Risk Premium (Canada)	5.71% (average) [Calculated from Bloomberg and Average long-term Consensus Forecast of 10-year government bond yields plus the average spread between 10- and 30-year bond]	2.5% [Usual range of 2-5%, with 3.5% being commonly used for average risk companies, and lower values for less risky companies]
Government Bond Yield (U.S.)	4.68% (average) [Bloomberg and Blue Chip Financial]	
Risk Premium (U.S.)	5.96% (average) [Calculated from Regulatory Research Associates, Bloomberg and Blue Chip]	
Financial Flexibility		0.50%
ROE	9.52% (Canada) 10.63% (U.S.) 10.04% (mean)	7.94%

[500] Concentric stated that “the equity risk premium is not directly observable...”. In its place, Concentric employs a regression analysis to assess the relationship between the authorized equity returns for utilities against 30-year government bonds. Data for over 700 U.S. and 60 Canadian electric utilities dating back as far as the early 1990s was input into Concentric’s analysis. Concentric also modeled variations of average long-term bond rates and then averaged the results. These results were added to the risk premium derived from the regression analysis to arrive at an overall risk premium return on equity, one for Canada, one for the U.S. and an average of the two.

[501] Dr. Cleary explained that his model examines the relationship between bond and stock markets using readily observable market-determined bond yields. He used current market long-term debt costs for A-rated utility bonds in Canada and the corresponding Bloomberg data for each utility. He noted that the yield on NS Power’s bonds maturing in 2042 was 4.94%, higher than the other utilities he analysed. He considered that this higher yield was a reflection of the other utilities holding higher credit ratings and longer maturity terms.

[502] To determine the risk premium side of the equation, Dr. Cleary contemplated that the typical range of risk premiums for utilities is between 2% and 5%. He considered that NS Power is a low risk regulated Canadian utility and suggested a low-risk premium between 2% and 3% is appropriate. He settled on 2.5%. Dr. Cleary then summed NS Power’s mid-point bond yield with this risk premium and applied an adjustment for flotation costs to arrive at 7.94%.

3.7.4 Party Submissions

[503] The Affordable Energy Coalition’s (AEC) opening statement submitted that the Board must ensure rates are sufficient to cover NS Power’s cost-of-service, while

preventing the recovery of excess spending and profits. The AEC characterized NS Power as a low risk regulated monopoly and argued that the utility should not face difficulty securing capital for its low-carbon investments. It also emphasized that many low-income Nova Scotians already experience significant cost-of-living pressures, making further rate increases untenable.

[504] The AEC's opening statement noted that Emera's annualized 10-year total shareholder returns ranged between 8.8% and 11.5% in 2022 and 2023 and questioned the justification for maintaining NS Power's 9% return on equity considering this profitability. The AEC submitted profit parameters should be adjusted to limit excess earnings and recommended reducing the return on equity to 7.6%, consistent with Dr. Cleary's evidence.

[505] In its closing submissions, NS Power argued that a fair return standard would warrant a higher return on equity and a thicker equity ratio based on Concentric's evidence, but it was maintaining its current return on equity and capital structure to balance affordability for customers:

In sum, NS Power is aware of the need to balance affordability for customers and the financial health of the utility and, as a component of the Settlement Agreement, is therefore seeking to maintain its current ROE of 9.0 percent and an equity ratio of 40 percent. The Company's requested 9.0 percent ROE is below the market-based cost of equity provided by Concentric. For its North American proxy group, most like NS Power, the range of results with market data as of January 31, 2025 was 9.29 to 10.32 percent, and updated in response to the Board's undertaking to 9.02 to 10.43 percent with market data as of December 31, 2025. Even the lowest estimate using the multi-stage DCF model exceeds the Company's requested ROE. [Footnotes omitted]

[NS Power Closing Submissions, p. 45]

[506] In addressing Dr. Cleary's evidence, NS Power contrasted the approaches taken by Concentric and Dr. Cleary. It said Concentric used proxy companies selected to match NS Power's business and operational risks, but Dr. Cleary relied on a very limited

group of companies that did not represent NS Power's business risk profile as a vertically integrated utility. It noted that in discussing the relative risk of Canadian and U.S. utilities in his evidence, Dr. Cleary focusses on utilities in Ontario and Alberta without considering how NS Power's risk profile may be different.

[507] NS Power submitted that Dr. Cleary's evidence was also undermined through his use of inputs based on his own personal judgement rather than current market data. It said other inputs and assumptions were not reasonable given the context of current and prospective economic and capital market conditions.

[508] In its closing submissions, the NDP Caucus encouraged the Board to "review the evidence presented by Dr. Cleary, who suggests Nova Scotia Power's rate of return should be set lower than the nine per cent".

[509] The Department of Energy filed closing submissions stating:

26. ...A higher ROE is clearly in NS Power's interests, but it is not in the public's interest that ratepayers are asked to pay more. This is particularly the case where ratepayers contribute to NS Power's returns despite poor reliability performance, including continually failed SAIDI and SAIFI standards, most notably in rural Nova Scotia. Much of Nova Scotia is rural, and power outages can deprive ratepayers not only of light and heat but also access to well water. NS Power should not be permitted to earn more by delivering less.

27. NS Power did not offer any rebuttal to Dr. Cleary's evidence. Dr. Cleary offers the best evidence in this proceeding with respect to appropriate ROE, noting that NS Power has, since 2012, earned its allowed ROE on average, exceeding the allowed ROE in 8 of 12 canvassed years.

[Department of Energy Closing Submissions, p. 5]

[510] In its reply submissions, NS Power addressed the Department of Energy's comments as follows:

The DOE has offered no justification for its request that NS Power's return on equity be set at 7.6 percent, other than the mere presence of Dr. Cleary's evidence on the record. While the DOE states that NS Power did not offer any rebuttal to Dr. Cleary's evidence, again this is not true, as Dr. Cleary's evidence was rebutted by Mr. Coyne in his oral testimony and also within NS Power's Closing Submissions. What should also be seen as rebuttal of Dr. Cleary's evidence is the agreement and support from customer representatives for the use of 9 percent as the return on equity. Notably, the DOE has offered no evidence or submissions to rebut the evidence of Mr. Coyne. In fact, the DOE's submissions do not reference Mr. Coyne's evidence at all; however, the DOE submissions do provide support

for Mr. Coyne's evidence as they only serve to further demonstrate NS Power's risk profile is higher than its peers. NS Power continues to rely on the evidence on the record in this proceeding and on its closing submissions to justify the requested, and customer representative-supported, 9 percent return on equity.

[NS Power Reply Submissions, pp. 9-10]

3.7.5 Findings

[511] It bears repeating that for at least a century, the Supreme Court of Canada has recognized that investors in regulated utilities are entitled to a fair return that is comparable to the return they would see from other investments of similar attractiveness, stability and certainty. Without this, investment may be discouraged and the utility may not be able to expand or maintain its operations, harming both its shareholders and its customers.

[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.

[513] The NSUARB considered this issue directly in its decision about NS Power's request to set new rates in 2005. In that case, the start of the hearing was delayed due to an early winter storm in November 2004 that left thousands of Nova Scotians without power – some for many days. In the wake of the storm, Premier John

Hamm asked the NSUARB to conduct an independent review of the utility's state of preparedness before the storm. Many questioned why a rate increase should be considered in the circumstances. The Board said:

[14] Just prior to November 15, 2004, the first scheduled day of the public hearing, NSPI requested that the hearing commencement be delayed until November 16, 2004. This request, which was agreed to by the Board, was as a result of significant power outages in various communities in the Province following a storm on November 13 and 14, 2004.

[15] The November outages are the subject of a separate review by this Board. On November 16, 2004, the Board received the following request from Premier John Hamm:

The Government of Nova Scotia believes that the public interest would be served if the Utility & Review Board conducted an independent review. I therefore request that the Utility & Review Board, under the powers of the Public Utilities Act, begin a public review of the Company's state of preparedness for, and response to, last weekend's storm.

This review should provide valuable insights into improvements which can be made to the overall restoration program in preparation for future outages.

[16] As part of the outage review, the Board has received a number of comments from members of the public questioning, among other things, why NSPI's request for a rate increase should be considered when the service provided by NSPI is, in the view of these customers, inadequate and unsatisfactory.

[17] While the Board recognizes the logic of this reaction, it is important to understand why this form of sanction cannot reasonably be applied to a regulated utility. NSPI is not like an unregulated retailer. It is a virtual monopoly which operates its business on a cost-of-service basis. Providing electricity to all communities in the Province was not (and likely still is not) financially feasible for private, competitive companies. For that reason, the Province's electric service supplier is a cost-of-service monopoly. In return for undertaking and continuing the costs of electrification of the Province, the Utility is permitted, under the Act, to recover the reasonable and prudent costs of providing this service. Because it is a monopoly, regulation operates as a surrogate for competition. One of the regulator's tasks is to balance the need for the Utility to recover its reasonable and prudent costs with the need to ensure that ratepayers are charged fair and reasonable rates.

[18] It is in the interests of all Nova Scotians to ensure that NSPI continues to be a stable and financially sound company. This is a reality which the Board must consider when determining what, if any, rate increase is warranted.

[19] In short, rates charged to customers are based on costs incurred by the Utility in providing service. If the Board finds certain costs to be imprudent or unreasonable, it can (and has) disallowed such expenditures and reduced proposed rate increases accordingly. The Board cannot, however, make rate decisions based solely on reliability issues or current public opinion of the Utility. There are appropriate sanctions a regulator can impose should a Utility be found to have an inadequate or unreliable system. In many cases, it is likely such sanctions would involve higher expenditures, rather than reductions in costs.

However, the practical reality in a regulated utility environment is that sanctions for service-related issues generally do not include a moratorium on rate increases.

[2005 NSUARB 27]

3.7.5.1 Return on Equity

[514] A utility's return on equity must be consistent with the fair return standard. There is no single test for determining an appropriate return on equity. Both experts in this proceeding used a variety of models and averaged the results of these models to produce a specific recommendation for an appropriate rate of return. However, the Board understands that each expert informed their opinion from the range of results from these approaches.

[515] In his evidence, Dr. Cleary said:

I have weighted all three of my [required return on equity] estimates equally because all three methods are used in practice and provide different perspectives on [required return on equity]. As discussed previously, CAPM is more heavily relied upon in practice due to its conceptual advantages. ...

CAPM is also more intuitive from the point of view of a utility cost of capital hearing. In particular, it has a direct relationship to financing costs (i.e., RF and MRP). The CAPM also makes a direct adjustment for the risk of utilities relative to the market, unlike DCF models, since it has a direct measure of risk (i.e., beta) included in the model. In addition, there are uncertainties associated with determining some of DCF input estimates for pure play regulated Canadian industries, as discussed earlier.

I also give equal weighting to the BYPRP [Bond Yield Plus Risk Premium] approach which is much more widely used than DCF approaches due to its intuitive nature, and because it adjusts for market-determined borrowing rates and risk. In fact, the BYPRP approach is more widely used than CAPM by Canadian CFOs, as mentioned earlier. Thus, the BYPRP approach accounts for interactions between company debt costs and equity markets, and as such it is intuitively sound.

[Exhibit N-32, pp. 74-75]

[516] Dr. Cleary gives equal weighting to the three approaches he used as his "best estimate" for allowed Canadian equity returns. At the hearing, he said that, properly implemented, all of these approaches "can provide useful guidance".

[517] In its evidence, Concentric noted:

No financial model can exactly pinpoint the correct [return on equity]; rather, each test brings its own perspective and set of inputs that inform the estimate of the [return on equity].

Consistent with the *Hope* standard, it is “the result reached, not the method employed, which is controlling.” Although each model brings a different perspective and adds depth to the analysis, each model also has its own inherent weaknesses and should not be relied upon individually without corroboration from other approaches. Regardless of which analyses are used to estimate the investor-required [return on equity], analysts must apply informed judgment to assess the reasonableness of results and to determine the appropriate weighting to apply to results under prevailing capital market conditions.

Other Canadian utility regulators, including the BCUC, the OEB, and the AUC, have acknowledged the need to use multiple methodologies in determining a fair return on equity. [Footnotes omitted]

[Exhibit N-8, Appendix 10A, p. 33]

[518] In addition to the inherent weakness across analytical models, it is apparent from the evidence in this proceeding that an expert’s selection of model inputs and their assumptions can also vary – in some cases, quite significantly. In some instances, the Board might have cause to question or give less weight to an input or assumption. In others, differences in approaches might be better described as points over which reasonable experts can disagree. The Board can use all this information to inform its conclusions about an appropriate return on equity.

[519] In the present case, the results of Dr. Cleary’s models produced a range of equity returns from 6.8% to 7.9%, with an average recommended return on equity of 7.6%. Concentric’s models, based on its Undertaking U-14, produced a range of results from 9.0% to 10.0%, with an average recommended return on equity of 9.4%. The Board finds that neither of the experts’ recommended averages meet the fair return standard. For reasons set out below, Dr. Cleary’s recommendation is too low and Concentric’s is too high. An appropriate return on equity for ratemaking purposes lies somewhere between these estimates.

[520] Before considering the strengths and weaknesses of the models, inputs and assumptions used by each expert, the inclusion of U.S. data in the assessments must be considered. This was a fundamental point of difference in the overall approaches taken

by each expert in this proceeding and fundamentally affects the results produced in their models.

[521] While the Board accepts Concentric's view that the economies of Canada and the U.S are highly integrated, the Board does not agree that this makes it appropriate to treat Canadian and U.S. data as fully interchangeable in a cost of capital analysis for a Canadian regulated utility. There are political and regulatory differences between the two countries. Dr. Cleary indicates there are corporate structural and operational differences between Canadian and U.S. regulated utilities. He submits Canadian utilities operate under more supportive regulatory environments. As noted, in his recent testimony before the Board in the NSPML 2026 cost assessment matter, he expressed the view that institutional and fixed income investors in Canada (and elsewhere) show a home-country bias for investment.

[522] The Board also observes some differences in the data filed in this proceeding. While suggesting some correlation, Concentric's response to Undertaking U-14 identified lower overall average total returns in Canada on the S&P/TSX compared to the S&P 500 in the U.S. over 25, 10 and 5 years (with a wider gap in the past 10 years); somewhat lower average real GDP growth in Canada relative to the U.S. over the past 25, 10 and 5 years; slightly lower inflation in Canada averaged over the same periods; and slightly lower 10-year government bond yields. In terms of the return on equity results, Concentric's Canadian proxy group produced the lowest results in all its models and the Canadian companies within its North American proxy group produced lower return on equity results than the U.S. companies in all its models.

[523] On the other hand, the Board does not agree with Dr. Cleary that U.S. regulated utility data should be entirely excluded. The pool of regulated utilities in Canada is far more limited than in the U.S., and in respect of fully integrated investor-owned utilities like NS Power, quite so. Comparing NS Power to regulated utilities in Canada may, in many respects, be more apt than to regulated utilities in the U.S. However, one must also be cautious about comparing NS Power to other Canadian utilities that do not share the same degree of risk, particularly risk associated with generation assets and the circumstances the utilities face in decarbonizing and the energy transition. The Board views Concentric's selection of its North American proxy group to be an attempt to address some of these other risks.

[524] Overall, the Board finds that, while it must be mindful that Concentric's use of U.S. data is likely inflating results in the analysis, Dr. Cleary's omission of U.S. utilities is likely producing results that are lower because the utility data he uses is largely comprised of a number of Canadian utilities that do not share NS Power's higher electricity generation or energy transition risks. The Board must consider and weigh the results from both experts accordingly.

[525] The Board notes the Ontario Energy Board reached a similar conclusion in its recent generic cost of capital proceeding:

Substantial differences remain between Canadian, and U.S.-based utilities principally associated with risk, regulatory oversight and the engagement of U.S. regulated utilities in non-regulated business operations. As well, holding company structures and business holdings, operating in the U.S. and not in Canada, decrease comparability of regulatory results. The OEB concludes that the "home bias" of the Canadian investor to invest in Canadian utilities is a factor in giving less weight to U.S. comparators. These differences cannot be ignored in the OEB's efforts to set parameters to meet the FRS.

...

The integration of U.S. and Canadian utility markets and the potential lure of higher returns for investors is a factor to be considered in arriving at a final conclusion concerning the requisite return on equity that must be provided to meet the FRS. However, the use of U.S.

regulated utility data as equivalent to Canadian regulated utility data in any computation is questionable.

[EB-2024-0063, pp. 36-37]

[526] The Alberta Utilities Commission had similar comments in its decision in its most recent generic cost of capital proceeding:

103. While the Commission finds that the U.S. companies have higher business risks than the Alberta utilities, for the purpose of establishing the comparator group, the Commission accepts the utilities' evidence that it is appropriate to include U.S. utility holding companies. The reasons for this are: (i) the relatively limited number of publicly traded Canadian utility companies; (ii) the prevalence of U.S. business operations among many publicly traded Canadian utilities; and (iii) investors' tendency to consider utility investment opportunities in both the U.S. and Canada. Further, the Commission remains of the view that it is reasonable to consider the U.S. market return data given the globalization of the world economy and integration of North American capital markets. Notwithstanding these findings, none of the Alberta utilities raises capital directly in the equity market, or operates outside of Alberta unlike a number of companies in the comparator group, which are holding companies and can operate anywhere.

104. After considering the evidence presented in this proceeding, the Commission acknowledges the utilities in the comparator group are not identical to the Alberta utilities, but concludes they are sufficiently comparable for use in various financial models. However, and as set out in in this section and Section 6.4.5, the Alberta utilities are at the low end of the range of risk present in the comparator group of utilities. Accordingly, the Commission retains the view expressed in the 2018 GCOC decision that a significant amount of judgment must be applied by the Commission when interpreting data from the representative utilities to establish the return on equity required by investors in the Alberta utilities. [Footnotes omitted]

[Decision 27084-D02-2023, p. 22]

[527] In the paragraphs that follow, the Board outlines its assessment of the models, inputs and assumptions advanced by the experts in this proceeding, beginning with the CAPM.

[528] Notwithstanding the statistical analysis Dr. Cleary provided in Appendix A to his evidence, it has not been sufficiently demonstrated in this proceeding that there is a systematic upward bias of Consensus Economics' forecasts of government bond yields used by Concentric to determine its risk-free rates in its CAPM. It would be surprising if any forecast of this nature matched actual results. And while Dr. Cleary's data showed several times when forecasts exceeded actuals, there were more recent periods when the reverse was true. However, the use of 10-year bond yields adjusted by historical

spreads to derive a 30-year bond yield introduces the need for other assumptions and procedures in the analysis that cause the Board to have less confidence in Concentric's results.

[529] The Board is also not satisfied that Dr. Cleary's use of 30-year government bond yields on a single day is likely to provide any better results. Aside from any issue about whether it is more appropriate to use a historical trend or a forecast, a single data point poses a greater risk of introducing an anomalous event impacting the metric on that day into the analysis.

[530] Because these witnesses tend to give similar evidence in regulatory proceedings in other jurisdictions, the Alberta Utilities Commission had similar comments on these issues relating to the evidence provided by the witnesses in its recent cost of capital proceeding:

110. In keeping with the prospective or forward-looking nature of the determination of the cost of capital and prior Commission practice, it is appropriate to use a forecast of the 30-year Canada bond yield submitted on the record of this proceeding. The Commission finds that a direct forecast of the 30-year Canada bond yield from Canadian major banks is simpler and more transparent than the approach recommended by Dr. Villadsen and Concentric, which uses the Consensus Economics forecast 10-year GoC bond yield and adjusts it by adding the average spread between 10- and 30-year government bonds. The need for this adjustment arises from the fact that Consensus Economics, on which Dr. Villadsen and Concentric rely, does not publish a forecast for the 30-year Canada bond yield. Similar adjustments have been used by the OEB and EUB for their formulas because of reliance on Consensus Forecasts.

111. The 30-year Canada bond yield forecasts are published by large, reputable Canadian financial institutions such as "the Big Six" banks. In the Commission's view, these forecasts are of comparable quality to the forecasts published by Consensus Economics. In fact, the Consensus Economics forecast is an average of estimates from various sources, including Canadian major banks. However, using direct forecasts of the 30-year Canada bond yield eliminates the need to make additional estimates and adjustments to the 10-year forecast for which there is no single, standardized approach. In addition, these forecasts are publicly available without cost. For simplicity, the Commission considers that averaging the forecasts from three banks, RBC, TD and Scotiabank, is sufficient. Should a forecast from one or more of these banks be unavailable, there are three additional major banks from which a forecast may be obtained as a substitute.

112. In addition to relying on bond yield forecasts published by the three banks, the Commission accepts in principle the approach of D. Madsen and Dr. Cleary to use a naïve forecast, using the actual 30-year GoC bond yield to inform an estimate of the future 30-

year GoC bond yield. The Commission has relied on this approach in past GCOC decisions to temper published forecasts because it accepted they tend to overestimate changes in interest rates. In this proceeding, representatives of customer groups made a similar point. However, the Commission considers it is better to use the average actual long-term GoC bond yields for an entire month rather than the yield that prevailed on any a single day in that month, as was done by Dr. Cleary and D. Madsen, to smooth out the daily volatility.

113. The Commission will use the bank forecasts published in February 2023 provided by D. D'Ascendis, as they were the most recent bank forecasts of long-term GoC bond yields provided on the record. For consistency, the Commission will use the average actual long-term GoC bond yield in February 2023 for the naïve forecast. [Footnotes omitted]

[Decision 27084-D02-2023, p. 24]

[531] Thus, while the risk-free rate estimates advanced by Concentric and Dr. Cleary are close (at least for the Canadian rate used with Concentric's Canadian utilities in its North American proxy group which is 3.87% compared to Dr. Cleary's 3.66%), the Board finds they are both subject to inherent weaknesses.

[532] Aside from the use of U.S. data, Dr. Cleary's other major complaint about Concentric's estimate for its market risk premium was about its use of "income only returns" rather than total returns which he said was standard for finance professionals. The Board considers there is merit in this criticism. As a result, it is likely that Concentric's market risk premium is also higher than it should be because of this issue.

[533] However, Dr. Cleary's market risk premium is not without its own vulnerability. While the Board has no specific reason to question Dr. Cleary's professional judgement and experience that market risk premiums generally fall within a range of 4%-6%, the assessment is more subjective. This is especially true about what part of the range should be used in any given case.

[534] Once again, Dr. Cleary's estimate of 5.5% is somewhat comparable to Concentric's 5.75% for its market risk premium. But because Concentric uses a blended market risk premium, its much higher U.S. estimate causes the premium it uses in its formula to be about 100 basis points higher than Dr. Cleary's market risk premium.

[535] The experts disagreed on the use of adjusted betas. To different extents, both suggested there was statistical or historical information supporting their respective positions. Given the evidence in this proceeding, a choice between these two approaches would be somewhat arbitrary. However, in the context of a return on equity analysis where the general approach is to analyse the issue using a number of different methods to better inform an overall result, using both adjusted and unadjusted betas could provide evidence of a range of results that may be reasonable. This is the approach taken by the Alberta Utilities Commission:

130. As expressed in several past decisions, the Commission remains unpersuaded that adjusted betas are superior to raw betas in the context of regulated utilities. Rather, it finds that both raw and adjusted betas can provide useful information with respect to utility risk. Similarly, the Commission continues to find that reliance on both weekly and monthly estimates of beta is reasonable.

...

132. The Commission concludes that utility stocks are appreciably less risky and volatile than equities in the broader market, and therefore considers a reasonable range of betas for regulated gas and electric utilities to be between 0.45 (representing Dr. Cleary's unadjusted long-term beta) and 0.75 (in the range of adjusted betas recommended by D. Madsen and D. D'Ascendis). The high end of Dr. Villadsen's beta estimates were well above this range. [Footnotes omitted]

[Decision 27084-D02-2023, p. 29]

[536] While the only evidence about ranges in this proceeding was the 0.3 to 0.6 range suggested by Dr. Cleary, the Board notes that Concentric's average beta in its CAPM was just a bit higher than that range, but within the range suggested in the Alberta Utility Commission decision. And as with his market risk premium assessment, Dr. Cleary's approach to estimating the beta within a generally accepted range is subjective, compared to the approach taken by Concentric.

[537] Overall, the Board's findings relating to the use of the CAPM model only reinforce the general observation that the results produced in Concentric's model are too high, and the results produced in Dr. Cleary's model are too low.

[538] The selection of growth rates was the most significant area of controversy about the application of the DCF approach by the experts. Concentric relies on analysts' earnings growth forecasts, which, Dr. Cleary said, are typically regarded as overly optimistic. While Concentric disagrees with this, it says any optimism bias was mitigated by using earnings growth forecasts from several sources.

[539] Dr. Cleary also noted that the overall growth rate implied by taking into account all stages of Concentric's multi-stage DCF exceeds nominal GDP growth. Dr. Cleary suggested this is "an ambitious target for low-risk utilities". He suggested such a rate assumes these utilities will outperform the productivity of Canada and the U.S. in perpetuity. Dr. Cleary considered this to be an unrealistic assumption for a utility. The Board finds there is merit in this criticism.

[540] On the other hand, Dr. Cleary's "sustainable growth rate" of 1.64% seems unreasonably low for a growth rate under a model that is presumed to continue to infinity. Dr. Cleary notes in his evidence around the application of his market DCF estimate, that "we are trying to estimate a 'nominal' required rate of return, so we should use nominal GDP growth". If the sustainable growth rate he uses in his Canadian utility DCF estimate is also intended to be nominal to derive a nominal required rate of return, and Dr. Cleary's assumed inflation rate is 2%, it seems especially low for a long-term assumption.

[541] Both of these points are also featured in the Alberta Utilities Commission's recent cost of capital decision:

153. In the 2018 GCOC decision, with reference to Dr. Cleary's evidence, the Commission recognized that the utilities are essentially monopolies in mature markets and, because of this, the use of long-term growth in excess of the long-term growth of GDP is unreasonable. Indeed, D. Madsen quoted in his evidence from a publication by Dr. Damodaran, who opined that it is questionable whether any firm is able to sustain high growth in the long term as it will eventually stop growing either due to limitations on size or to the effects of competition.

154. On the other hand, the sustainable growth rate Dr. Cleary used to estimate expected dividend growth rates relied on historical seven-year average dividend yields and payout ratios and used accounting data, rather than readily available, market-driven forecasts. The Commission notes that this approach produces growth estimates that are less than actual historical rates of dividend growth and less than inflation, resulting in negative real growth. As a result, the Commission is concerned that Dr. Cleary's sustainable growth rate produces results that understate dividend growth. [Footnotes omitted]

[Decision 27084-D02-2023, p. 34.]

[542] As with the Board's conclusion about the CAPM, the growth rates used by the experts in their DCF models reinforce the Board's general observation that the results produced in Concentric's model are too high, and the results produced in Dr. Cleary's model are too low.

[543] The regression analysis in Concentric's risk premium model uses long-term government bond yields and equity risk premiums. The equity risk premiums in the regression analysis are obtained from the difference between regulator allowed ROEs and 30-year government bond yields. The bond yields in the Canadian version of this model use the same approach as the calculation of the risk-free rate in its CAPM model and are therefore subject to the same weaknesses.

[544] The Board is concerned about the nature of this approach. Using authorized equity returns from other jurisdictions reflects regulatory decisions shaped by legislation, policies and economic conditions that may be unique to those jurisdictions. They are not directly derived from market-based data and are only indirectly derived to the extent that the regulator approving the return on equity considered and accounted for market data.

[545] In his evidence, Dr. Cleary submitted that authorized ROEs have not declined adequately in response to reductions in government and A-rated utility bond yields over the last two decades. Based on the evidence in this proceeding, it is not clearly demonstrated to the Board that this is correct; however, to the extent that there was any

“stickiness” in allowed ROEs, following the risk premium approach used by Concentric would likely contribute to that.

[546] Dr. Cleary’s risk premium approach uses utility bond yields and adds a risk premium. As with elements of his other models, the risk premium exhibits a high degree of subjectivity through the selection of a point, generally in the range of 2 to 5%, based on the deemed riskiness of the company. The evidence about this in this proceeding lacked empirical rigour.

[547] The Alberta Utilities Commission also had concerns about these approaches and refused to rely on them in its recent cost of capital decision:

165. In addition to relying on CAPM and DCF models, some parties used the following risk premium models to help inform their fair return on equity estimates: (i) Concentric and Dr. Villadsen used the government bond yield risk premium model; (ii) Dr. Cleary and D. D’Ascendis relied on the utility bond risk yield premium model; and (iii) D. D’Ascendis used the predictive risk premium model. The Commission determines that it will not rely on any of these models for the purposes of the present decision.

166. The government bond risk premium approach estimates the return on equity as the sum of the ERP and the yield on the 30-year U.S. Treasury bond. The ERP was calculated as the difference between authorized returns from U.S. electric and gas utilities and the then-prevailing quarterly 30-year U.S. Treasury yield. Consistent with prior GCOC decisions, the Commission continues to be of the view that the approved ROEs from other jurisdictions are not, strictly speaking, wholly market-based data and therefore, will not place any weight on the results of the government bond risk premium model.

167. Under the utility bond risk premium approach, a required return on equity is calculated by adding an equity premium to a utility bond yield. In past GCOC decisions, the Commission accepted the bond yield and utility bond yield approaches to be valid tools in estimating the cost of equity, as they are simple to use and conform to the basic principle that investors require a higher return for assets with greater risk. Although the Commission still considers the empirical basis of the utility bond yield methodology to be valid, for the purposes of this decision the Commission will not rely on the utility bond yield risk premium approaches used by Dr. Cleary and D. D’Ascendis.

168. Dr. Cleary’s recommended risk premium of 2.50 per cent is subjective, not supported by any analysis and does not take into the account the changing market environment.

[548] In this case, the Board finds that the risk premium models are of quite limited value, even relative to the other models with their weaknesses, and will weigh them accordingly.

[549] Having reviewed the return on equity models in detail, the Board finds that Concentric's recommendation is too high and Dr. Cleary's is too low. The evidence in this matter does not support adopting either, but it does firmly support setting a return on equity within that range. However, evidence supporting the selection of a specific point between these two recommendations is less firm.

[550] The parties to the settlement agreement agreed to maintain NS Power's current return on equity of 9% for ratemaking purposes, with an earnings band of 8.75% to 9.25%. Under this proposal, the Board notes that any earnings above 9.25% would be returned to customers under s. 64C of the *Public Utilities Act*. However, NS Power is not entitled to any additional recovery in the event earnings are below 8.75%.

[551] The Board finds it is appropriate to accept this proposal under the settlement agreement for several reasons. As discussed, the evidence does not support adopting the recommended rates of either Concentric or Dr. Cleary, and the proposal under the settlement agreement falls within these rates which the Board considers too high and too low. In other aspects of this decision, where the Board has found that the evidence supported a departure from the settlement agreement, and the Board has determined it is in the public interest to do so, it has departed from what was proposed. But as noted, the evidence does not otherwise point to a better placement for the return on equity within the high and low points set by the expert evidence.

[552] The parties to the settlement agreement are sophisticated parties who represent the interests of all NS Power's rate classes. These parties participated in a pre-application review of NS Power's proposed rate increases that involved focussed discussions with NS Power to resolve matters of disagreement arising from NS Power's

proposed application. These parties are typically the most active in Board proceedings involving NS Power and frequently present the Board with expert evidence and submissions on matters of concern. Given this, the Board has some comfort that the public interest has been addressed.

[553] Notwithstanding his views, Dr. Cleary recognized the settlement agreement was a factor for the Board to consider in setting NS Power's return on equity:

The settlement agreement that was reached by NS Power and customer representatives recommends [*sic*] a continuation of NS Power's currently allowed return on equity of 9% and 40% equity ratio. While remaining confident in my market-based return on equity and equity ratio recommendations, I acknowledge that reaching a settlement agreement does involve trade-offs that the Board must take into consideration.

[Exhibit N-32, p. 6]

[554] While, as noted above, the Board finds it inappropriate to calculate a required return on equity using authorized equity returns, the Board finds it acceptable to reference returns awarded elsewhere in Canada in the context of assessing the overall reasonableness of the settlement agreement. Considering Figure 30 from Concentric's evidence (reproduced earlier in this decision), it is apparent that maintaining NS Power's return on equity would not make it an outlier in Canada, with most of the other Canadian electric utilities falling within a narrow range. The only utility with an appreciably lower return on equity was Newfoundland Power (8.6%), a Crown corporation with a higher equity ratio at 45%.

[555] In the hearing for NSP Maritime Link's 2026 annual assessment (Matter M12394), Dr. Cleary was asked to respond to a statement made by Concentric that a 7.6% return on equity would be the lowest authorized return on equity of an investor-owned regulated utility in North America. Dr. Cleary responded, "[t]o the best of my knowledge, 7.6% would be the lowest recommended return on equity in Canada".

[556] Setting a rate of return that low could have far reaching consequences. This was the subject of comment by the Ontario Energy Board, where Dr. Cleary recently recommended an even lower return on equity of 7.05% for utilities in that province:

There is evidentiary support for a significant reduction to the current return on equity advanced by Dr. Cleary. Both Dr. Cleary and LEI are instructive in providing reassurance that the regulator has discharged its responsibility to the utilities it regulates in meeting the FRS for their continued operation. The remaining question is whether the current return on equity results in rates that are greater than required to meet that standard thereby generating economic rent from utility customers.

Dr. Cleary's evidence endeavors to show a result that could meet that question in the affirmative. The effort produces a result that differs markedly from the other expert evidence by recommending a considerably lower estimate, with much of that difference attributable to his reluctance to accept the comparability of Canadian utilities with U.S. counterparts. His model thus engages a smaller number of comparators. As noted earlier, the OEB also has concerns about the ability to find true comparators from the U.S., which limits the number of comparators that might be definitively used.

However, a significant recommended change from the results of the current formula that has been meeting the FRS for utilities must be done with caution. The submissions of the EDA and the OEA set out potential concerns regarding an return on equity reduction such as recommended in Dr. Cleary's proposal. The OEA pointed to the risk of negative credit rating impacts, which could increase the cost of debt financing for Ontario utilities and impose additional costs on ratepayers. The OEA also emphasized that setting an return on equity at an insufficient level would constrain the growth prospects of Ontario utilities by reducing projected earnings per share growth, potentially forcing utilities to offer higher dividend payouts to attract equity investment. These outcomes would create financial pressures inconsistent with the requirement that utilities earn a fair return. Dr. Cleary himself acknowledged that a steep drop in return on equity could create instability for regulated utilities from a credit rating standpoint. [Footnotes omitted]

[OEB EB-2024-0063, pp. 38-39.]

[557] As noted, NS Power's current credit rating from S&P already places it in the bottom 10% of utilities in North America. The evidence in this proceeding, especially the evidence presented by Morrison Park that was discussed elsewhere in this decision, already raises concern about NS Power's ability to maintain even its current low rating. A failure to do so could cause its cost of debt (which comprises 60% of NS Power's capital structure) to increase and result in other financial consequences to the detriment of NS Power's customers. Morrison Park said, should NS Power's rate requests be rejected and its securitization plan not bear fruit, then it would be a certainty that the 10% FFO:Debt

target would be missed in both 2026 and 2027 and put NS Power at risk of further credit rating downgrades. Setting a return on equity at 7.6% would materially reduce NS Power's funds from operations and make its 10% FFO:Debt target more difficult to achieve.

[558] The Board finds it would not be in the public interest to approve a return on equity that does not meet the fair return standard and deviates materially from the range of equity returns authorized for similar utilities across Canada. This reluctance is heightened by the array of investment disincentives identified in the evidence of Morrison Park, which collectively underscore the importance of maintaining NS Power's ability to attract capital and preventing any further deterioration of the utility's credit rating that would likely result in increased costs for customers.

[559] To ensure NS Power can undertake required significant capital investments, the Board acknowledges that investors will assess the relative attractiveness of investing in NS Power compared with other Canadian utilities. The Board finds that maintaining a return on equity of 9.0% for rate-setting purposes, with an earnings band of 8.75% to 9.25%, is in the long-term interests of customers.

3.7.5.2 Capital Structure

[560] NS Power proposed to maintain its capital structure of 40% equity and 60% debt. This request was supported by its expert witness Concentric (which considered 45% would be appropriate), Board Counsel consultant, Dr. Cleary, and the signatories to the settlement agreement. No party opposed NS Power's request. The Board finds it is appropriate to accept the proposal in the settlement agreement to maintain NS Power's capital structure.

3.8 Cost of Service Study

[561] Under the *PUA*, a utility is afforded the opportunity to recover its “reasonable and prudent” costs of providing service and a “just and reasonable” return on its rate base. The total amount of these costs and the return on rate base is generally referred to as the utility’s “revenue requirement”.

[562] Once the revenue requirement is determined, customer rates are set to produce revenue equal to this amount. Under s. 67(1) of the *PUA*, rates charged to customers “under substantially similar circumstances and conditions in respect of service of the same description” must be charged equally to all customers.

[563] Grouping customers into classes that receive service under substantially similar circumstances and conditions requires judgement. Many factors influence this determination. In L.R. Nash, *Public Utility Rate Structures* (New York and London: McGraw-Hill Book Company Inc., 1933), p. 273, the author states:

Discrimination is commonly understood to mean a difference in rates or service conditions relating thereto for service of substantially the same characteristics, taking into account volume, load factor, load density, time of use, character of use, and any other significant factors. Because of the many factors involved in discrimination, its precise definition is necessarily left to the judgement of the regulatory commissions in each case.

[564] In *Dalhousie Legal Aid Service v Nova Scotia Power Inc.*, 2006 NSCA 74, the Court of Appeal noted that differences in rates charged to customers may only be justified based on how they receive service from the utility. Other differences, such as a customer’s ability to pay, cannot be used to establish rates in Nova Scotia (based on the legislation as it is currently written):

[23] DLA’s factum said that low income customers do not have “substantially similar circumstances” to higher income customers. So, different rates would not be barred by s. 67(1). At the appeal hearing DLA’s counsel retreated somewhat from this submission.

[24] With respect, the factum’s submission misinterprets s. 67(1). The provision refers to “substantially similar circumstances and conditions **in respect of service of the same description.**” To justify a rate difference, the relevant dissimilarity is not in customers’

incomes. It is in the service from NSP. The Board accepted, and there is no basis to question, that NSP provides substantially similar electrical service whatever the domestic customer's income.

[25] Section 67(1) is mandatory. The rates and charges "shall always . . . be charged equally" to persons of similar circumstances and conditions in respect of service. The statute does not endow the Board with discretion to consider the social justice of reduced rates for low income customers. It is not for the Board or this court to read into s. 67(1) the words:

. . . similar circumstances and conditions in respect of *the income level of customers and* service of the same description,

It is for the Legislature to decide whether to expand the Board's purview with the italicized words. [Emphasis in original]

[565] The same rationale applies to the request for the creation of a Mi'kmaq Rate Class, as set out in the Letter of Comment sent to the Board on behalf of the Kwilmu'kw Maw-klusuaqn Negotiation Office (KMKNO) and the Assembly of Nova Scotia Mi'kmaw Chiefs [Exhibit N-1, pp. 24-26]. The socio-economic, housing, geographic, and demographic factors discussed in the Letter of Comment do not relate to differences in the way electricity is provided to Mi'kmaq households, businesses and community buildings, which is similar to how it is provided to households, businesses and community buildings outside of Mi'kmaq communities. Rather, those differences relate to the unique circumstances and conditions of the Mi'kmaq communities themselves. The statute does not allow the Board to set a separate rate based on customer-related differences, only service-related differences.

[566] Although rates must be charged equally to customers "under substantially similar circumstances and conditions in respect of service of the same description", responsibility for the revenue requirement is not divided equally among NS Power's customer classes. This is because different classes of customers do not use the electrical system in the same way. They take service under different circumstances and conditions and impose different costs on the system. For example, to serve domestic customers, the

utility must have an extensive distribution system. Large industrial customers may not require this infrastructure and, therefore, the cost to serve these two classes of customers may be quite different.

[567] The utility's revenue requirement must be fairly divided among its customer classes based on how each class contributes to system costs. A fair allocation of costs ensures that all customer classes pay for the costs of the service they receive and their rates do not subsidize the rates of other customer classes. This allocation of costs is performed using a cost-of-service study, which is prepared by the utility and identifies the costs attributable to each customer class.

[568] Despite involving a considerable amount of system and customer data, the distribution of costs under a cost-of-service study is not an exact science. As NS Power's consultant, Andrew Blair, Elenchus Research Associates Inc., noted in response to questions at the hearing, a cost-of-service study involves a lot of judgement and, in some respects, may be considered more of an art than a science:

Q. And, Mr. Blair, do you agree that the cost of service allocation it's not a pure science?

A. (Blair) That's right. It's often said it's more of an art than a science.

Q. Yeah, there's a lot of subjectivity, generalization, averaging, simplification that's involved in the processes?

A. (Blair) Yes, there's a lot of judgment that goes into what the methodology should be and then it sort of turns into a science from there. But, yeah, at the first stage there's a lot of judgment.

Q. And would you agree that as a result many regulators often recognize sort of a range of reasonableness as the outcome of cost allocations, so in this particular jurisdiction so the 95 percent to 105 as opposed to trying to precisely target 100 percent allocation under a particular method to each rate class?

A. (Blair) Yes. I believe a range of reasonableness is used in every jurisdiction in Canada for electricity.

Q. And in this particular model the end result is showing for the residential class a 97.18 percent under a revenue-to-cost ratio. That's -- I'm interpreting the table correctly?

A. (Blair) That's correct.

Q. Yeah. And so consistent with what you just said, we wouldn't necessarily think of that as being subsidized by other rate classes. It's within that range of reasonableness and, you know, within the range of that's appropriate costs that are allocated to that particular class?

A. (Blair) Yes, that's right.

[Transcript, January 7, 2026, pp. 163-164]

[569] In NS Power's case, costs are directly allocated to a specific rate class when this is possible because they are clearly and directly connected to that class. An example of this is the capital and maintenance related costs of streetlight fixtures, which are assigned directly to streetlight classes based on information acquired from NS Power's financial books and records or through additional analysis or studies. Shared costs that are not directly assigned are analyzed in the cost-of-service study.

[570] The first step in the process is to identify costs based on the high-level function they serve in providing overall service to customers. In NS Power's case, costs are functionalized into groups based on whether they relate to production, transmission, distribution or retail functions.

[571] After this step, the functionalized costs are classified based on their relationship with different services. Generally speaking, demand costs relate to the utility's capacity to provide service to customers, energy costs relate to the energy provided to customers, and customer costs are costs that are driven by the number of customers served.

[572] Next, various factors are developed to allocate the classified costs to NS Power's customer classes. These allocation factors may consider certain characteristics of the customer class such as the number of customers, the demand that the customer class imposes on the system, and the amount of energy used to serve the customer class.

[573] It has been more than 10 years since NS Power's cost-of-service methodology has been comprehensively reviewed in a proceeding before the regulator. The last proceeding focused on cost-of-service methodologies that was before the NSUARB occurred in 2014 (2014 NSUARB 53).

[574] Since then, there have been concerns that changes in the electricity sector warranted a review and potential updating of NS Power's cost-of-service methodologies. These changes include increasingly stringent requirements to decarbonize, the development of the Maritime Link and access to market energy, increased regional wind and solar penetration, grid scale battery storage, increased reliance on purchased power agreements and increased investment intended to support electrification and distributed energy resources. As a result, in NS Power's last general rate application, the utility and several intervenors agreed that a cost-of-service study would be completed through an engagement process before NS Power's next general rate application (or by December 31, 2025, whichever was sooner).

[575] In its decision, the NSUARB agreed that NS Power's cost-of-service study should be updated to reflect developments impacting NS Power's system since the last review of its cost-of-service study in 2013/2014. The NSUARB directed that all cost allocation methodologies should be reviewed for their continued relevance and application.

[576] In the present application, NS Power provided information about the engagement process it followed in developing the cost-of-service proposals it has put forward for approval. NS Power's summary of this process in its application stated:

Throughout 2024, technical conferences were held to provide in-depth educational sessions on the current COS treatment at NS Power and identify the primary issues to be resolved as part of the formal regulatory process, areas requiring additional examination,

and areas of consensus and disagreement among parties. The goal of these sessions was for the Company to determine its view of the appropriate path forward, ideally with the development of a consensus agreement. This process culminated in two full-day Resolution Sessions. These sessions were held in person with stakeholders and expert consultants present, and NS Power retained Bruce Outhouse (KC) to mediate these sessions.

The process proved to be beneficial and has served to streamline COS discussions in the context of the GRA. NS Power received positive feedback from stakeholders concerning the opportunity for productive discussion and the breadth of information provided in this process. An extensive exchange of information took place through presentations, modelling, and data request (DR) cycles across the year. 67 models and iterations of models were prepared and are attached to this COSS as **Appendix 12A(1)**. In addition to that, stakeholders asked 152 DRs, these DRs and NS Power's responses to those DRs are appended to this COSS as **Appendix 12A(2)**. Other information provided included presentations and slide decks provided by NS Power and its consultants, appended as **Appendix 12A(3)**, jurisdictional scans, appended as **Appendix 12A(4)**, and memorandums, appended as **Appendix 12A(5)**. [Emphasis in original]

[Exhibit N-9, p. 7]

[577] Exhibit N-9 also included information about the cost-of-service models run throughout the consultation process, responses to information requests, presentations, jurisdictional scans, memos and a formal report from NS Power's cost-of-service study consultant, Elenchus.

[578] NS Power's proposed methodologies are listed in Table 2 in Elenchus' report:

Table 2 – Summary of NS Power Proposed Methodology

	Status Quo	Change
Generation	<ul style="list-style-type: none"> Allocation except for treatment of purchased power 	<ul style="list-style-type: none"> No initial classification to energy for environmental and fuel conversion reasons Use system load factor⁵ for classification of all generation, including purchased power Refunctionalize radial-to-generation from Transmission Create new storage sub-function Allocate non-fuel, energy related costs of all purchased power monthly
Transmission	<ul style="list-style-type: none"> Bulk Power substations refunctionalized to distribution Allocation 	<ul style="list-style-type: none"> Refunctionalize radial-to-generation to Generation Classify all Transmission as 100% Demand Create new storage sub-function No distinction between EHV and HV
Distribution	<ul style="list-style-type: none"> Sub-functions Classification Allocation 	<ul style="list-style-type: none"> Create new storage sub-function
Other	<ul style="list-style-type: none"> Retail classification & allocation 	<ul style="list-style-type: none"> General Plant review Cost allocation applicable to PHP above-the-line⁶
		<ul style="list-style-type: none"> DSM rate rider – all DSM costs assigned directly. No system benefit allocation. DDA methodology New line losses

[Exhibit N-9, PDF, pp. 1675-1676]

[579] The proposed changes to NS Power’s cost-of-service methodologies are described in more detail in Exhibit N-9, Appendix 12A, Part 5.0 and Appendix 12B. The following is a summary of these changes:

Classification of Generation Costs by System Load Factor

NS Power’s current approach to the classification of generation-related fixed costs such as depreciation and financing costs is to first classify environmental and fuel conversion-related capital costs to energy. A

secondary step classifies peaking assets 100% to demand, wind assets using effective load carrying capability, and categorizes the remaining generation assets using the system load factor. NS Power proposes to end the initial classification of environmental and fuel conversion-related capital costs and to classify all generation assets using the system load factor.

Fuel Adjustment Mechanism Related Cost Sub-Functionalization

Fuel adjustment mechanism related purchases that provide firm capacity will be classified between energy and demand based on the system load factor, while purchases that provide no capacity, such as non-firm imports, will be classified 100% to energy. This will align purchased power agreements providing firm capacity with the treatment of generation assets and recognizes that non-firm purchased power agreements provide energy only.

Classification of Transmission Costs 100% to Demand

NS Power currently uses the system load factor to classify transmission rate base and costs to energy and demand. To reflect anticipated need for increased investment in the transmission system, reduced dependence on coal fired generation in Cape Breton, increased wind generation and a shift away from radial to network system design, NS Power proposes to classify transmissions costs 100% to demand.

Transmission Links to Other Systems

NS Power proposes that transmission links to other systems, such as interties with the grids of other provinces, should generally be functionalized 100% to transmission and therefore classified 100% to demand. NS Power notes this does not have an immediate impact because this category of asset does not currently exist in its rate base.

Removal of the Distinction between Extra High Voltage and High Voltage

NS Power proposes to remove its current distinction between extra high voltage and high voltage and apply a single sub-function for these items. NS Power said there is no real separation between the two systems and this approach would be simpler.

Treatment of Battery Storage

Battery storage is presently functionalized to transmission, but NS Power proposes that battery storage should be considered on a case-by-case basis to determine if the asset is primarily supporting a generation, transmission or distribution function. NS Power noted that the grid scale batteries currently being developed will primarily serve generation, so they are proposed to be functionalized to generation and to be classified based on the system load factor.

Changes to Open Access Transmission Tarriff to Align Bundled and Unbundled Service

NS Power said methodological differences in how rates are set for transmission service in the unbundled market under the Open Access Transmission Tariff (OATT) and the bundled market under its cost-of-service study result in customers paying different amounts for the same transmission service. To align the cost of transmission service between the bundled and unbundled services more closely, NS Power proposes that:

- Transmission revenue requirement applicable under the OATT be set the same as under the cost-of-service study methodology.
- Cost-of-service transmission costs be classified 100% to demand.
- Transmission usage in OATT rate calculations reflect forecasted test year usage.

Radial to Generation

NS Power proposes that radial-to-generation assets, as defined under the OATT, be re-functionalized from transmission to generation in the cost-of-service study for consistent treatment of these assets under the transmission pricing methodologies in the bundled and unbundled markets and to better align with other North American utilities and the Federal Energy Regulatory Commission's pro forma OATT design that provided the foundation for NS Power's OATT.

Demand Side Management Rider

Demand side management costs are currently allocated as 75% to the cost of programs undertaken for the rate class and 25% to the system benefit of the programs. NS Power is proposing to remove the allocation to system benefit, so that 100% of the program costs will be allocated to the benefiting class.

Treatment of Port Hawkesbury Paper as an Above-the-Line Customer

Port Hawkesbury Paper is currently served under a below-the-line rate with a term ending on December 31, 2026 (2025 NSEB 16). In the cost-of-service studies for 2026 and 2027, PHP has been modeled as taking service under an above-the-line rate with the following load characteristics:

- Firm load of 8 MW at the three coincident peaks (3CP) in December, January, and February;
- Total load (firm plus interruptible) of 65 MW at the 3CP; and
- Energy set using PHP forecast net of projected supply from the PHP Goose Harbour Lake Wind Farm.

General Plant

General plant primarily consists of NS Power's investment in facilities, such as buildings structures and grounds, communication equipment, vehicles and information technology infrastructure. Currently, costs are apportioned to generation, transmission and distribution, based on the relative net book value of these three service areas. NS Power proposes that general plant in projects above \$1 million be allocated to any clear and identifiable function. For example, vehicle costs are attributable to transmission and distribution far more than generation, so the utility proposes that these costs be allocated between transmission and distribution. The portion of costs to be allocated between each function would be determined by using allocators such as operating costs and rate base.

Decarbonization Deferral Account

NS Power considers its approved decarbonization deferral account to be a rate stabilization tool and proposes that it be classified and allocated in the same manner as other rate stabilization tools.

[580] Relative to NS Power's existing cost-of-service methodologies, the proposed changes negatively impact residential customers. While the costs allocated to almost every other rate class are lower under the proposed methodology, they are approximately \$26 million higher for the domestic class in 2026 and \$25.3 million in 2027 (NSEB IR-127 [Exhibit N-27, pp. 537-538]).

[581] The parties to the settlement agreement included the following terms relating to cost-of-service methodology used to determine rates for 2026 and 2027:

Cost of Service ("COS")	a) The COS as set out in the Draft GRA will be included in the 2026-2027 GRA and put forward for approval, subject to the following: (a) use of the Minimum System methodology after the 2026-2027 test period will be subject to a future proceeding and determination by the Board, for which an application will be made in 2026 and in which parties are free to take any position they so choose; (b) NS Power will collect and disclose the data outlining the extent to which PHP uses, relies upon and/or benefits from the High Voltage transmission system and in any proceeding to determine rates for PHP after the 2026-2027 test period, Parties may make submissions regarding the extent to which PHP is to be responsible for any costs of the High Voltage transmission system; and (c) the appropriate apportionment of assessment costs from the Maritime Link as between generation and transmission will remain open to be addressed as Parties see fit in any proceeding to determine rates after the 2026-2027 test period.
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[Exhibit N-27, NSEB IR-001, Attachment 1, p. 10]

[582] Carolyn Palmer, Synapse Energy Economics, was engaged by Board counsel to review NS Power's cost-of-service study. In her evidence, Ms. Palmer expressed concern about the way that portions of NS Power's distribution system were classified as customer related. She also had concerns about other proposed changes to NS Power's proposed cost-of-service methodologies, but she did not provide specific evidence about those concerns because of the settlement agreement. Indeed, despite her recommendations, Ms. Palmer did not specifically oppose the settlement agreement but said these issues should be reviewed:

Q. Considering the consensus agreement in this GRA, what do you recommend regarding the Company's COSS methods?

A. While I do not support several of the Company's COSS methodologies, particularly the use of the minimum system method for classifying distribution system costs, I recognize that the parties have overcome their own concerns with the proposed methodologies to reach a settlement in this case and I therefore do not oppose their settlement agreement in this GRA. However, I believe that the COSS proposals contained within the settlement should be treated as case-specific and non-precedential in future cases. Therefore, I recommend that the Board find that certain COSS methodologies put forward in this case must be revisited in the next GRA. ...

[Exhibit N-37, pp. 17-18]

[583] In its closing submissions, Renewall Energy Inc. expressed concern about what it considered to be inconsistencies between NS Power's cost-of-service methodologies and the methods used to determine Open Access Transmission Tariff (OATT) charges.

3.8.1 Findings

[584] For the purposes of setting rates in this proceeding, the Board accepts the proposed cost-of-service changes and the cost-of-service studies presented in this proceeding, except NS Power is directed to implement a load carrying capability adjustment to account for the demand component served by the minimum system used to classify distribution system costs. This issue is discussed in more detail below.

[585] The Board also directs NS Power to address the additional cost-of-service concerns raised by Ms. Palmer in its application to the Board later this year, in addition to the minimum system versus basic customer method debated for allocating distribution system costs. NS Power is also directed to further address the issues raised by Renewall if the utility brings forward any application relating to the OATT tariff or charges before responsibility for the transmission tariff is transferred to the Nova Scotia Independent Energy System Operator. These issues are also further discussed below.

3.8.2 Minimum System v. Basic Customer Methods

[586] NS Power's cost-of-service study classifies portions of its distribution system as customer-related using the minimum system method. Under this approach, a minimum system study estimates what the cost of a distribution system would be if all poles, fixtures and wires were sized to minimum specifications. The costs of this hypothetical system are deemed to be customer-related costs. The remaining costs of the distribution system are considered to be demand-related.

[587] NS Power submitted that minimum system or zero-intercept studies are generally used for classifying distribution system costs in Canada. Two jurisdictional scans were included in the evidence before the Board in this proceeding. The first was in evidence filed by Concentric Energy Advisors on behalf of NS Power in its last general rate application, and was included in the engagement process materials for the cost-of-service study filed in this matter. The results from that assessment are reproduced below:

Figure 1: Canada Results Summary

Utility	MSS Used?	Poles, Towers and Fixtures	Conductors	Line Transformers
Nova Scotia Power (Current)		PRI: 27% Customer, 73% Demand; SEC: 50% Customer, 50% Demand	PRI Overhead/Underground: 27% Customer, 73% Demand; SEC Overhead/Underground: 50% Customer, 50% Demand	100% Demand
Nova Scotia Power (Proposed)	Yes	PRI: 76% Customer, 24% Demand; SEC: 70% Customer, 30% Demand	PRI Overhead: 38% Customer, 62% Demand; SEC Overhead: 83% Customer, 17% Demand; PRI Underground: 17% Customer, 83% Demand; SEC Underground: 82% Customer, 18% Demand	100% Demand
ATCO Electric	Yes	55% Customer, 45% Demand	Overhead: 70% Customer, 30% Demand; Underground: 70% Customer, 30% Demand	55% Customer (Non-Rural); 60% Customer (Rural); (50% Rural Allocated)
BC Hydro	No	50% Customer, 50% Demand	50% Customer, 50% Demand	50% Customer, 50% Demand
Fortis BC Energy	Yes	81% Customer, 19% Demand	65% Customer, 35% Demand	69% Customer, 31% Demand
Maritime Electric	No	50% Site (Customer), 50% Demand	50% Site, 50% Demand	40% Site; 60% Demand
New Brunswick Power	No	50% Customer, 50% Demand	50% Customer, 50% Demand	25% Customer, 75% Demand
Newfoundland Power	Yes	37% Customer, 63% Demand	37% Customer, 63% Demand	28% Customer, 72% Demand
Ontario	No	60% Customer if Density is < 30 customers per kM of lines, 40% Customer if Density between 30 and 60 customers per kM of lines, 35% Customer if Density between > 60 customers per kM of lines, or 30% Customer if Density is between > 60 customers per kM of lines		
SaskPower	Yes	70% Customer, 30% Demand	70% Customer, 30% Demand	35% Customer, 65% Demand

[Exhibit N-9, PDF pp. 62-63]

[588] The other was prepared by Elenchus and is also found in the engagement process cost-of service materials filed in this matter:

Utility	Transformers	Primary	Secondary
BC Hydro	Judgement (50%/50%)	Judgement (100% Demand)	Judgement (50%/50%)
SaskPower	Minimum System		
Manitoba Hydro	PUB Order (100% Demand)		
Ontario Distributors	Judgement (with consideration of Minimum System analysis)		
Hydro Quebec	Minimum System		
NB Power	Judgement (with consideration of Minimum System and Zero-Intercept analyses)		
NS Power	100% Demand	Minimum System	
Maritime Electric	Judgement (60% Demand)	Judgement (50%/50%)	
NL Power	Zero-Intercept	Minimum System	

[Exhibit N-9, PDF p. 1471]

[589] Ms. Palmer agreed that NS Power’s use of the minimum system method is not unique and that it is used in other jurisdictions throughout Canada. However, she did not believe this means it is a reasonable method to use for classifying distribution infrastructure.

[590] Ms. Palmer said the minimum system method does not align with NS Power’s definition and treatment of customer costs because these costs do not vary directly with the number of customers. She said:

For example, if the Company adds a new residential customer with a negligible level of demand in a populated area, the additional distribution costs to serve that customer—aside from dedicated customer infrastructure—would generally also be negligible, because no significant demand is being added by the new customer. If, however, the new customer were to add a substantial amount of additional demand, then distribution system upgrades would be required, increasing costs. Thus, these costs are primarily driven by demand, rather than by the number of customers. It is only when the distribution system must be expanded to a new geographic area that an incremental customer impacts distribution system costs independently from the customer’s level of demand.

This example demonstrates that the presence of a residential customer does not necessarily impose additional distribution costs (apart from costs related to that customer’s demand) unless the system must be expanded to a new geographic area. Indeed, NS Power states that the customer-related portion of feeder investment “is driven by the need to bring electric service to geographically dispersed customer locations.” Thus, there is little justification for classifying costs in these accounts as customer-related.

[Exhibit N-37, pp. 6-7]

[591] Ms. Palmer said the number of poles and the amount of wire required to serve customers is more likely to vary based on the distance of development from other infrastructure and that geography is not necessarily well-correlated with the number of

customers. She said the minimum system method does not include a measure to account for geographic dispersion.

[592] Ms. Palmer recommended classifying distribution costs using the basic customer method, as described in the Regulatory Assistance Project's manual *Electric Cost Allocation for a New Era*. She said this method was used across North America. Following this method, only costs associated with services, meters, meter reading and billing are generally classified as customer-related.

[593] Ms. Palmer considered that the use of the minimum system method overstates the costs classified as customer-related. She also noted that because the residential class has more customers than other classes, customer-related costs are far more heavily allocated to residential customers.

[594] In response to NSEB IR-128, NS Power calculated the impact on costs allocated to customer classes using the basic customer method. The result of this analysis showed that using the basic customer method shifted about \$30 million in costs away from the residential class to other rate classes, with most of that difference moving to the general service class. In response to Undertaking U-5, NS Power provided calculations showing the impact on proposed rate changes in this proceeding if the basic customer method was used instead of the minimum system method (along with certain other corrections), as set out below:

Customer Class	Proposed COSS Methodology		Modified COSS Methodology as per U-5		Variance	
	Smoothed		Smoothed		Smoothed	
	2026	2027	2026	2027	2026	2027
Domestic	3.8	4.1	2.2	2.8	(1.6)	(1.3)
Small General	3.6	3.9	1.7	2.4	(1.9)	(1.4)
General	(0.2)	0.6	3.1	3.5	3.3	2.9
Large General	(4.5)	(3.1)	(2.2)	(1.3)	2.3	1.8
Large General	(0.5)	0.3	3.0	3.3	3.5	3.0
Medium Industrial	(6.5)	(4.8)	(3.1)	(2.2)	3.4	2.5
Large Industrial	(7.0)	(4.7)	(6.0)	(3.8)	0.9	0.9
Municipal	1.7	3.1	3.0	3.9	1.3	0.8
Unmetered Classes	7.9	7.2	2.9	3.1	(5.0)	(4.1)
Total	1.7	2.4	1.7	2.4	(0.0)	(0.0)

[Exhibit N-76, p. 1]

[595] As can be seen from the table above, the change to the basic customer method would reduce the proposed increases for the domestic, small general and unmetered rate classes, but increase the rate changes for the rest of NS Power’s above-the-line rate classes. However, the large general, medium industrial and large industrial classes still see overall rate reductions in both test years. The Board understands the second reference to “Large General” in the exhibit is an error and should be “Small Industrial”.

[596] Mr. Blair suggested that the number of recognised methods for allocating distribution system costs was limited:

Q. Is there a — I know it was referenced in Elenchus's evidence, as well as perhaps Ms. Palmer's evidence, there is reference to I think the Zero Intercept method. Is that kind of a hybrid sort of methodology that would sort of fall between the Minimum System method and the Basic Customer method?

A. (Blair) It’s really more like the Minimum System method, but instead of it being a Minimum System that has some delivery capacity it’s a hypothetical system that reaches every customers but doesn’t have any delivery capability at all.

Q. Okay. And are those really the three basic methods that are primarily used in cost-of-service studies?

A. (Blair) Yes, that's right. And there's often multiple ones considered and then some kind of judgmental percentage applied to them is necessarily the results of each one.

[Transcript, January 7, 2026, p. 155]

[597] In response to questions from the Board at the hearing, Mr. Blair also agreed that the basic customer method would classify the smallest amount of distribution system costs as customer-related and the minimum system method would classify the highest amount.

[598] Both Mr. Blair and Ms. Palmer agreed that the classification of distribution system costs is one of the most controversial aspects of determining cost-of-service. This is likely because these costs cannot be neatly identified as being driven primarily by an increase in customers or in demand.

[599] Although Mr. Blair considered the geographic size of the distribution system to be more closely aligned with an increase in customers than Ms. Palmer, he acknowledged that this is an area where costs are "not exactly caused by one of the three usual allocators of customer, energy and demand". Similarly, in response to questions from NS Power at the hearing, Ms. Palmer agreed that costs relating to the geographic dispersion of the system were not well correlated with an allocation based on either the number of customers or demand.

[600] Professor Bonbright noted this problem in *Principles of Public Utility Rates*:

The really controversial aspect of customer cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers, but also a substantial fraction of the annual maintenance and capital costs of the secondary (low-voltage) distribution system – a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage while keeping them from falling of their own weight. In any case, the annual costs of this phantom, minimum-sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else

with the links of the distribution lines, depending on the type of distribution system), they therefore vary directly with the number of customers. Alternatively, they are calculated by the “zero-intercept” method whereby regression equations are run relating costs to various sizes of equipment and eventually solving for the cost of a zero-sized system (Sterzinger, 1981).

What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile square mile quote). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatsoever in the costs of a minimum sized distribution system.

While, for the reason just suggested, the inclusion of the costs of a minimum size distribution system among the customer related cost seems to us clearly indefensible, its exclusion from the demand related cost stands on much firmer ground. For this exclusion of minimum size distribution system costs makes more plausible the assumption that the *remaining* cost of the secondary distribution system is a cost which varies continuously (and, perhaps, even more or less directly) with the maximum demand imposed on the system as measured by peak load.

But if the hypothetical costs of a minimum size distribution system is properly excluded from the demand related costs for the reason just given, while it is also denied a place among the customer costs for the reasons stated previously, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that “the sum of the parts equals the whole.” They are therefore under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any other cost categories.

In actual practice the vast majority of utilities utilize some form of minimum system to classify costs, which is in line with the FERC accounts. Sterzinger (1981) is critical of this practice and recommends that to avoid the overcollection of costs from low-use residential customers, regulators should classify distribution costs as demand costs. Neither of these procedures can be justified as a cost allocation in the sense of directly assignable costs, for they are nonassignable.

Allocation, in whole or in part, would be at least theoretically possible if a customer density parameter were added to the three traditional cost components. But if this factor were embodied, not only in cost analysis but in the resulting rate differentials, rates would not be uniform throughout a given community and hence would violate a generally accepted tradition (see Watkins, 1921, p. 212 and Havlik, 1938, Chapter 8 and Appendix A). [Emphasis added]

[pp. 491-492]

[601] Although Ms. Palmer recommended the use of the basic customer method, she recognized that the parties to the settlement agreement had agreed to defer that matter for a more detailed consideration in 2026. On that basis, she does not oppose the

settlement agreement, although she urged the Board to direct that other proposed changes to NS Power's cost-of-service methodologies also be considered in that process. She also suggested that, if the Board were to allow the classification of distribution system costs using a minimum system study, it could consider doing so only for the secondary distribution system and classifying primary distribution system costs to demand. Additionally, she submitted an adjustment should be made to recognize the minimum system's peak load carrying capability. These issues are discussed in more detail later in this decision.

[602] In their closing submissions, parties to the settlement agreement urged the Board accept the terms of the settlement agreement and allow the proposed changes to the cost-of-service methodology to stand, pending an application later this year which would address the classification of distribution system costs under the minimum system or basic customer method for future proceedings. They emphasized the extensive nature of the engagement process leading to the settlement agreement and the fact that unresolved issues relating to this matter are going to be addressed in a another proceeding later this year.

[603] The Industrial Group submitted that Ms. Palmer's evidence was narrow and did not provide a proper basis to make the cost-of-service changes she recommended at this time. The Industrial Group also emphasized the impact such changes would have on non-residential customers:

Synapse's evidence on the Basic Customer method was shown on cross-examination to be narrow, lacking both a jurisdictional scan and Nova Scotia-specific analysis.

The record further shows that the Basic Customer approach is scarcely used in Canada—Manitoba being the only example, and even there it is now under review, with evidence filed outlining significant flaws in the method. Those criticisms include that even the smallest customer drives meaningful distribution costs, and that ignoring minimum system

requirements distorts cost causation. While Ms. Palmer characterizes the minimum-system method as flawed, it remains recognized in the NARUC Cost Allocation Manual.

...

Response to Undertaking U-5 provides the rates resulting from this single proposed change. The residential class would see a reduction of 1.6% in 2026 (smoothed rates) relative to what has been applied for but each of General, Large General and Medium Industrial would increase approximately 3.5%. ...

The Board has been clear that rate impacts cannot be assessed in isolation. All-in customer bill effects, including base rates, the FAM AA/BA rider, and the DSM rider, should be considered together. The full scope of rates and riders were considered by the customer representatives and informed the Consensus Agreement.

If the Board were to modify aspects of the COSS allocation methodology, it would have a disproportionate impact on certain rate classes. Modifications would benefit residential classes, who are experiencing a higher base rate increase in the GRA but significantly burden other classes, including the General rate class and the Medium and Large Industrial classes, which will have an overall higher rate increase for 2026 once the riders are considered.

Given the incomplete record, introducing methodological changes at this time would be premature and could lead to unintended rate consequences. The parties intentionally carved out the Minimum System issue for a separate, dedicated proceeding in 2026 to allow appropriate time for expert analysis, proper collection of data, evaluation of alternative methods, and a complete evidentiary process. [Emphasis added] [Footnotes omitted]

[Industrial Group Closing Submissions, pp. 7-8]

[604] These sentiments were shared by the MEUs. The MEUs also noted that the use of the minimum system method was of particular interest to them because they also used it to determine rates for their customers:

As the Board is aware, the MEUs currently use the Minimum System methodology as part of their own COS methodologies in developing rates for their customers. Like NS Power and its consultant, Elenchus, the MEUs support the use of the Minimum System methodology. Clearly, the issue is one of the most controversial aspects in cost allocation in utility rate-making, and has been that way “forever”, as the Chair suggested in his questions to NS Power’s COS Panel. The MEUs recognize that Synapse, an American consulting firm, has repeatedly expressed its preference for use of the Basic Customer method in multiple Nova Scotia proceedings in recent years. But there is also no doubt that the Minimum System method is one of the recognized cost-of-service methods used in Canada, and it has been approved for use in Nova Scotia for all electric utilities for decades.

[MEUs Closing Submissions, p. 2]

[605] In its submissions, the Consumer Advocate noted:

The Consumer Advocate shares Ms. Palmer’s concerns regarding the Minimum System Method, and through the Settlement Agreement, and resulting GRA, NS Power has agreed that the use of the Minimum System Method after the test years will be the subject of a

separate proceeding before the Board that will be initiated later this year by an application from Nova Scotia Power. The Consumer Advocate continues to support that approach. As with any aspect of the GRA, it is up to the Board to determine if this is a sufficient response to the issue or if some other remedy is required to provide for rates that are “just and reasonable.”

[Consumer Advocate Closing Submissions, p. 8]

[606] The Nova Scotia New Democratic Party Caucus and the Nova Scotia Liberal Party Caucus urged the Board to implement Ms. Palmer's recommendation to adopt the basic customer method to classify distribution system costs. The New Democratic Party submitted that this method would be “less biased against residential customers, so that Nova Scotian households don't bear an outsized burden of any increase”. The Liberal Party submitted switching to the basic customer method “could reduce the increase faced by customers”.

[607] NS Power submitted that the COSS filed in support of its rates in this proceeding provided the most appropriate basis for allocating costs among customer classes following cost causation principles.

3.8.2.1 Findings

[608] Under a cost-of-service model, the objective is to fairly allocate costs to customers based on cost causation. This has been a chronically difficult thing to do for distribution system costs. It would be inappropriate to direct the use of the basic customer method to classify distribution system costs simply to reduce the rate increase for residential customers. It would be just as inappropriate not to do so because of the impact that would have on other customers (with or without rate rider impacts). However, the parties did not fully press this issue in this proceeding due to the settlement agreement and the Board requires more information to further assess the cost causation basis for adopting the basic customer method. As explained below, these issues will be brought before the Board for further consideration in a cost-of-service proceeding later this year.

[609] From the evidence in this proceeding, both cost-of-service experts acknowledge that neither the minimum system method nor the basic customer method is perfect because distribution system costs are not correlated well enough with either the number of customers or the demand on the system by those customers. It is somewhat telling that the same problem discussed by Professor Bonbright nearly 40 years ago continues today.

[610] While the Board supports settlement agreements, it is very concerned that in the face of the other significant changes that have been proposed to the cost-of-service, NS Power has proposed to leave this issue unaddressed in this proceeding for what appears to the Board to be the expediency of bringing forward a consensus position to support its general rate application. Unfortunately, the Board is now in a position where it finds that neither of the proposed methods for classifying distribution system costs is wholly adequate. Based on the closing submissions filed in this proceeding, it appears there may be more that the parties would like to say.

[611] One option to address this problem would be to require this issue to be further addressed before the Board rendered a final decision in this matter. This would, of course, delay the implementation of new rates. Were it not for the concerns about NS Power's ability to maintain its credit metrics well enough to avoid a costly downgrade (discussed in more detail elsewhere in this decision), this may very well have been the result. NS Power should bear this in mind in the event it brings forward settlement agreements in the future that leave significant issues both unaddressed in the agreement and proposed to remain that way in the final decision in the matter.

[612] The Board considers that broader participation from customer groups is necessary to provide a more appropriate basis for determining this question and therefore finds it is not able to resolve this issue in this proceeding. The Board therefore accepts that this will be further considered by NS Power and brought back to the Board later this year when it can be more openly considered and debated. While this is not an entirely satisfactory result, the Board takes some comfort that, despite her position, Ms. Palmer was prepared to accept the consensus position on this point – subject to a caveat that will be addressed later in this decision.

3.8.3 Primary Distribution System

[613] If the basic customer method is not used to allocate distribution system costs between customer and demand, then Ms. Palmer recommends that the primary distribution system be classified 100% to demand. Ms. Palmer expressed concern that the minimum system methodology used in the cost-of-service study included NS Power's primary electric system distribution lines notwithstanding that the residential customer class likely does not receive service directly at primary voltage. Ms. Palmer submitted that primary infrastructure is shared, is more likely to peak at the same time as system peaks and is likely higher-voltage than the customer-specific equipment (meters and services) directly serving the majority of electricity customers.

[614] According to an analysis undertaken by Concentric in 2022, in advance of NS Power's last general rate application, nearly 65% of distribution system poles were sub-functionalized to primary distribution, while nearly 80% of overhead conductors were found to be part of the primary distribution system:

	Poles	Overhead Conductors	Underground Conductors
Primary - Demand	15%	49%	6%
Primary - Customer	49%	30%	1%
Secondary - Demand	11%	3%	17%
Secondary - Customer	25%	17%	76%

[Exhibit N-9, PDF p. 1225]

[615] Based on the jurisdictional scan that was undertaken by Elenchus and reproduced previously in this decision, NS Power submitted that Saskatchewan, Quebec, and Newfoundland and Labrador use the minimum system method for both primary and secondary distribution systems, while the approaches used in Ontario and New Brunswick are grounded in judgement with some consideration of the minimum system.

3.8.3.1 Findings

[616] As with the discussion about the use of the minimum system method or the basic customer method, the Board finds that a more satisfactory resolution of this issue would result from a broader debate about this issue. The Board therefore directs that this issue be specifically analysed and considered in the engagement process intended to address the appropriate classification of distribution system costs. To be clear, the matter should not be resolved based on a jurisdictional scan alone. The Board expects the issues identified by Ms. Palmer to be comprehensively addressed in the proceeding. In particular, this should include but not be limited to the manner in which the primary distribution system is used and shared by the various customer classes, the extent to which residential customers receive service directly at primary voltages and whether their equipment can be served at those voltages, and the demand on the primary distribution system relative to the system peak.

3.8.4 Peak Load Carrying Capability Adjustment

[617] Ms. Palmer also recommended that a peak load carrying capability adjustment be applied to account for the demand component served by the minimum system, if the basic customer method is not used to classify distribution system costs between customer and demand. She noted that poles and wires of any size have a load-carrying capacity that will necessarily serve a portion of a customer's demand and submitted this should be recognized. In response to questions from Board Counsel at the hearing, NS Power agreed that even a theoretical minimum system has load carrying capability and will necessarily serve a portion of customer demand.

[618] Ms. Palmer advised that a peak load carrying capability adjustment of 0.4 kW/customer is applied for the assumed peak load carrying capability of the minimum system in Ontario. She also said that in its most recent rate cases, Excel Energy in Minnesota and South Dakota had assumed a peak load carrying capability of 1.5 kW/customer for the minimum system and applied this adjustment to its distribution capacity cost allocation factors. She also noted that National Grid, in New York, recently proposed not allocating any demand-related costs for the minimum system distribution infrastructure to residential and small commercial customers on the premise that the minimum system would be able to meet the peak load for all or almost all customers in these classes.

[619] Ms. Palmer recommended that NS Power implement a peak load carrying capability adjustment for any infrastructure cost classified using its minimum system study. She acknowledged that a specific adjustment would require thoughtful analysis but, in the absence of a specific calculation, recommended that each customer class be

credited with 1.5 kW/customer to the non-coincidental peak demands used for determining minimum system demand allocators.

[620] Based on her pre-filed evidence and her responses to questions at the hearing, it is apparent that Ms. Palmer's recommended credit was intended to be used as a proxy until NS Power calculated a more accurate peak load carrying capability adjustment. As she explained at the hearing:

Q. And you recommend 1.5 kilowatt per customer, which is outside of the range of what we reviewed from Ontario. So could you confirm, and perhaps you explained to my friend, but I'm still not clear about exactly how you came up to that number.

A. Like I discussed with Ms. Power, there are kind of three examples that I've seen that I put in my testimony; the .4 from Ontario, the 1.5 from Minnesota and South Dakota, and then New York State's, or National Grid in New York State, proposing to simply assign no demand costs to its residential and small commercial customers.

And this seems to be kind of in the middle of that. There's the range of adjustments that I'm aware of that I presented, and this is kind of a middle route. I've acknowledged it's an approximation and that it will be superior to have Nova Scotia Power's analysis when available.

[Transcript, January 13, 2026, pp. 1311-1312]

[621] In response to Undertaking U-6, NS Power calculated the impact on rates if a 1.5 kW/customer adjustment was applied as a credit to the non-coincidental peak demand for determining the minimum system demand allocators of the distribution system costs. The result was to shift responsibility for about \$7 million in costs away from the residential class to other rate classes, with most of that difference moving to the general service class. As shown in the table from the undertaking response, reproduced below, applying such a peak load carrying capability adjustment would reduce the proposed increases for the domestic, small general and unmetered rate classes, but increase the rate changes for the rest of NS Power's above-the-line rate classes. However, the large general, medium industrial and large industrial classes still see overall

rate reductions in both test years. The Board understands the second reference to “Large General” in the exhibit is an error and should be “Small Industrial”.

Customer Class	Proposed COSS Methodology		Modified COSS Methodology as per U-6		Variance	
	Smoothed		Smoothed		Smoothed	
	2026	2027	2026	2027	2026	2027
Domestic	3.8	4.1	3.2	3.7	(0.6)	(0.4)
Small General	3.6	3.9	3.4	3.8	(0.2)	(0.1)
General	(0.2)	0.6	0.9	1.4	1.0	0.9
Large General	(4.5)	(3.1)	(3.7)	(2.5)	0.7	0.7
Large General	(0.5)	0.3	0.5	1.1	1.0	0.8
Medium Industrial	(6.5)	(4.8)	(5.6)	(4.0)	0.9	0.7
Large Industrial	(7.0)	(4.7)	(6.6)	(4.3)	0.4	0.4
Municipal	1.7	3.1	2.2	3.4	0.5	0.3
Unmetered Classes	7.9	7.2	7.0	6.3	(0.9)	(0.9)
Total	1.7	2.4	1.7	2.4	(0.0)	0.0

[Exhibit N-77, p. 1]

[622] In response to questions from NS Power at the hearing, Ms. Palmer agreed that the peak load carrying capability adjustment used in Connecticut was heavily influenced by the capacity adjustment associated with line transformers. The capacity adjustments for all other equipment were less than 0.4 kW/customer. Ms. Palmer also acknowledged that NS Power’s cost-of-service methodology allocates transformers as 100% demand-related.

[623] In its closing submissions, NS Power submitted that the implementation of a peak load carrying capability adjustment would have significant consequences for other rate classes and that such a change “should not be taken lightly”. NS Power emphasized that determining an appropriate peak load carrying capability adjustment for its minimum system required thoughtful analysis and that there was no basis in the evidence in this proceeding to assign an adjustment of 1.5 kW/customer at this time. As noted already, the other parties to the settlement agreement expressed concerns about implementing

Ms. Palmer's recommendations given the balance that was achieved under the settlement and the impact that these recommendations would have on non-residential customers, due to the shifting of costs and the impact of rate riders that will be applied in addition to the base rates determined in this general rate application.

3.8.4.1 Findings

[624] Notwithstanding the settlement agreement, the Board finds that it is appropriate to direct NS Power to implement a load carrying capability adjustment in this proceeding. Unlike the evidence relating to the use of the minimum system method or the basic customer method for classifying distribution system costs, where neither approach seemed sufficiently supported by the evidence in this proceeding, it appeared that both cost-of-service experts (and NS Power) agreed that a minimum system has some load carrying capability. The Board finds this should be addressed now, rather than wait for the process planned for later this year, and then not be implemented for another year or more. Further, the issue of a load-carrying capability adjustment must be decided on its own merits and not depending on whether it reduces rate increases for some customers classes or puts upward rate pressures on other classes (with or without rate rider impacts).

[625] The evidence uniformly supported that, although subject to some complexity, it was possible to determine more precisely the load carrying capability of the minimum system assessed for NS Power's system. As noted, NS Power submitted there was no basis in the evidence in this proceeding to assign an adjustment of 1.5 kW/customer at this time. This is true because evidence of this nature was not provided by NS Power in this proceeding. At the same time, there is evidence that a minimum system has some load carrying capability, so NS Power's election to assign no

adjustment at all would, on the limited evidence that is before the Board in this matter, appear to be the least supported approach.

[626] Based on the information provided in this proceeding, the Board directs NS Power to implement a load carrying capability adjustment of 0.4 kW/customer to its minimum system method. The Board finds that the number used in Ontario is an appropriate proxy pending a more precise determination by NS Power. In doing so, the Board accepts that the 1.5 kW/customer adjustment used by Excel Energy is influenced by the capacity associated with line transformers that are already classified fully to demand in NS Power's case, making it a less appropriate proxy. NS Power is directed to make this adjustment in a compliance filing in this matter.

[627] The Board also directs NS Power to undertake the analysis necessary to calculate the load carrying capability of its minimum system. This must be done before NS Power engages with customer representatives in the proceeding contemplated in the settlement agreement, and this analysis must be included in the application resulting from that process that NS Power will file with the Board later this year.

3.8.5 Other Cost-of-Service Issues Raised by Synapse

[628] As noted already in this decision, in addition to her concerns about the use of the minimum system method to classify distribution system costs, Ms. Palmer had concerns about certain other proposed changes to NS Power's cost-of-service methodologies. However, rather than elaborate on these concerns in her evidence, and recognizing that the settlement agreement contemplated a future proceeding before the Board to address the use of the minimum system methodology after the 2026-2027 test period, she elected instead to recommend that the Board direct that the future proceeding also include an examination of other cost-of-service changes as well. These include NS

Power's departure from its current approach to classifying generation costs, in which it now proposes to classify all generation assets using the system load factor; NS Power's departure from its current approach to classifying transmission costs, in which it now proposes to classify 100% of transmission costs to demand; and the potential for NS Power to use more granular and temporal allocators (noting that further data analysis and discussion would likely be worthwhile in considering moving away from the three coincident peak generation and transmission demand cost allocation and non-coincident peak distribution demand cost allocation).

[629] In response to questions from Board Counsel at the hearing, NS Power suggested that the settlement agreement contemplated that the only outstanding issue that would be addressed in the future proceeding noted in the agreement was the use of the minimum system method beyond the test years in the current general rate application:

Q. So N-37, page 20 in the PDF, line 16. Here Ms. Palmer has identified additional Cost-of-Service Study methods that she thinks should be reviewed as part of whatever future process occurs, and she lists out the three areas here. Has Nova Scotia Power had a opportunity to consider those, and do you have a position on whether you agree with those being part of consideration in future cost-of-service matters?

A. (Williams) Thanks, Mr. Mahody. I think what the Settlement Agreement does is it expressly identifies Minimum System as being subject to what we would see as a standalone application or matter that we would bring to the Board in 2026, and that's what's described in the Settlement Agreement. And as it says in the Settlement Agreement, any party may take any position they so choose.

Subsequent to the test period, the '26-'27 test period, we would not — our expectation is not that the Settlement Agreement or the positions that parties have taken in relation to the Settlement Agreement in any way binds them, and all cost-of-service issues would be before the Board for consideration at the next General Rate Application or the next standalone cost-of-service proceeding.

That said, I think there is an expectation -- I know there is an expectation from Nova Scotia Power, and I would think there's a similar expectation from all parties, that we're not redoing the same extensive cost-of-service process that we just undertook in relation to all cost-of-service matters in subsequent proceedings. I would expect that we do get some value out of what we just went through, but certainly the Minimum System is one that was identified as being for further consideration.

Q. Okay. And so back to Ms. Palmer's three additional methods that she is recommending you reviewed. Do you agree that the next point, Cost-of-Service Study — a full Cost-of-Service Study is being undertaken, that those matters should be considered?

A. (Williams) I think the next time a full Cost-of-Service Study was undertaken all matters would be out there. But as I said, no-one's bound as a result of this process or the agreement, but certainly the expectation would be that we've reached common ground on certain aspects of these.

I think where my uncertainty in terms of the recommendation lies is when you read from line 9 it says:

I recommend that the Board expressly state that not only should the [minimum system] methodology be subject to a future proceeding and determination...but that the same requirement should apply to several other [cost-of-service] methods...

And so if Ms. Palmer's intention there is to include these other methods in the 2026 filing that's described and expressly set out in the Settlement Agreement, we would disagree with that recommendation and we would not feel that that's the expectation of Nova Scotia Power. But if she's referring to future cost-of-service studies, then, as I said, I think all issues would be subject to the Board's consideration and assessment in that setting.

[Transcript, January 7, 2026, pp. 127-130]

[630] In its closing submissions, Port Hawkesbury Paper endorsed NS Power's testimony on this point. It also argued that the parties needed certainty and stability about these points:

Based on the considerable record before the Board, PHP submits that the recommendations made by Synapse at pages 18-19 of its evidence (Ex. N-37) that "several other COSS methods" in addition to the minimum system methodology should be subject to a future proceeding and determination by the Board should not be accepted at this time. The COSS provides the underpinning costs to be collected from the various rate classes, and a level of stability is appropriate in this regard as has historically been the case in Nova Scotia.

[Port Hawkesbury Paper Closing Submissions, p. 6]

3.8.5.1 Findings

[631] It is clear that Ms. Palmer has some misgivings about other aspects of NS Power's cost-of-service methods, but in light of the settlement agreement, she elected to focus on the minimum system vs. basic customer issue and leave the others to the future process she understood was contemplated under the settlement agreement. Although the Board places weight on the fact that informed participants have agreed to a resolution of these issues, when the Board is considering whether it is in the public interest to accept

the settlement agreement, the existence of a settlement agreement is certainly not dispositive of that issue.

[632] The traditional role of Board Counsel and consultants is to ensure that the Board has an appropriate record before it to render a fully informed decision. If Synapse believes these issues are worth raising for the Board to consider, the Board would prefer that it do so, precisely because cost-of-service issues have tended to remain in place for extended periods in this jurisdiction. Therefore, the Board directs NS Power to specifically address the areas of concern identified by Ms. Palmer in the application NS Power expects to file with the Board later this year.

3.8.6 Issues Raised by Renewall Energy Inc.

[633] As mentioned earlier in this decision, in its closing submissions, Renewall said there were inconsistencies between NS Power's cost-of-service methodologies and the methods used to determine OATT charges. Renewall's focus was on the impact of these inconsistencies on rates in the renewable-to-retail market, in which it is currently the only licensed retail supplier. Renewall also highlighted the Board's obligation to appropriately consider the extent to which its decisions support the development of a competitive electricity market under s. 6(2) of the *Energy and Regulatory Boards Act*.

[634] NS Power submitted:

NS Power applied the approved OATT and COS methodologies, as amended in the Settlement Agreement, to determine the proposed bundled and OATT charges. The transmission costs are allocated to the bundled rate classes based on class contribution to the three winter month peaks of January, February, and December (three coincident peaks, 3CP) whereas allocation of these costs to the open market transmission services of point-to-point and network are done on the basis of their contribution to the twelve calendar months (12CP). The difference in approach to the allocation of transmission costs in these two markets was discussed and accepted by the intervenors to the 2005 OATT founding proceeding. [footnotes omitted]

[NS Power Reply Submissions, p. 26]

[635] One of Renewall's concerns was that the system coincident factor used in the cost-of-service study (78.6%) [Exhibit N-67, Attachment 1, p. 79 of 99] did not match the system coincident factor used in the OATT rate development tables (91.66%) [Exhibit N-17(vi), Figure 5-13]. Renewall noted that using the cost-of-service system coincident factor in the calculation for the monthly billing rate for network service reduced the charge by over 14%.

[636] NS Power said the coincident factors were two different calculations serving two different purposes. It said the factor in the OATT calculations determines system non-coincident demand billing determinants on the basis that the monthly \$ per MW charges under the OATT are calculated such that application of the proposed OATT charges yields the OATT revenue requirement. NS Power noted the factor of 78.6% is not used directly in rate calculations.

[637] Renewall also noted that the system peaks in the cost-of-service and OATT calculations do not match. It observed that, for 2026, the OATT calculations assume a coincident peak of 1,778 MW and a non-coincident demand of 1,939 MW [Exhibit N-17(vi), Figure 5-10] (i.e., coincidence factor of 91.7%), while COSS Exhibit 9A suggests a coincident peak of 2,095 MW and a non-coincident peak of 2,667 MW [Exhibit N-67, Attachment 1, p. 79 of 99] (i.e., coincidence factor of 78.6%).

[638] While it did not expect the differences to produce a material impact, Renewall also noted what it considered to be other inconsistencies. For example, it noted that formulas in the cells used to determine the revenue requirement for load following and 10-minute supplemental operating reserve in Exhibit N-17(vii) (Summary Rates, cells B27 and B29) did not appear to be consistent with Exhibit N-17(vi), Figure 6-8. In its reply

submissions, NS Power appeared to accept that the figures in Exhibit N-17(vii) and (ix) (Summary Rates) were incorrect, but said these pertain only to “side calculations” and do not impact the proposed OATT rates.

[639] In concluding its comments in its reply submissions in response to the issues raised by Renewall, NS Power said:

REI suggests that coincident factors and system peaks drive the transmission and ancillary service components of the OATT, and using the updated COSS would result in lower OATT costs per MW. This is false. As indicated above, the coincidence factors from ‘Exhibit 9a Annual’ are not relevant to the calculation of the OATT rates.

As demonstrated above, the proposed OATT rate calculations are accurate and consistent with the approved methodology. The OATT calculation process has been revised to better align with the COS through the COSS stakeholder consultation process conducted in 2024 and incorporated into the 2026-2027 GRA.

Overall, it does not appear that REI is asking the Board to reject any aspect of the COS as proposed or that REI is challenging the OATT; however, it seems that REI is asking the Board to treat the COS as completely determinative of OATT inputs, rather than as a separate construct.

It is important to note that no complete COS will ever be fully mirrored in the calculation of OATT rates. Further, in the future as outlined in the *More Access to Energy Act*, the Independent Energy System Operator of Nova Scotia (IESO Nova Scotia) will administer the OATT once relevant sections are proclaimed. It will be up to the IESO Nova Scotia to determine how it will incorporate the COS from market entities into the OATT structure.

Differences between COS and OATT inputs do not, in and of themselves, indicate errors or overcollection. NS Power continues to engage with REI through its established monthly check-ins and welcomes all further opportunity to walk through the OATT methodology and assumptions in greater detail and address any remaining questions on these points. [footnotes omitted]

[NS Power Reply to Closing Submissions, pp. 27-28]

3.8.6.1 Findings

[640] Because these technical issues were only raised in closing submissions, the Board has a poor record before it to make an informed decision on these points. As a result, the Board accepts the relevant calculations included in the settlement agreement.

[641] However, Renewall correctly points out that the Board must appropriately consider how its decisions support competition and innovation in the provision of energy resources in the province and the development of a competitive electricity market. In this regard, NS Power's response that "the proposed OATT rate calculations are accurate and consistent with the approved methodology" is not entirely satisfactory. The real question is whether that dated methodology continues to be appropriate.

[642] Although responsibility for the transmission tariff will, at some point, transfer to the Nova Scotia Independent Energy System Operator, it is not entirely clear when that will occur. The most recent information from IESO Nova Scotia suggests an "aspirational timeline" for this transition in the second quarter of 2027. Furthermore, under s. 83 of the *More Access to Energy Act*, SNS 2024, IESO Nova Scotia will inherit the existing transmission tariff at that time, which will remain in force until it is changed by IESO Nova Scotia. Therefore, if NS Power brings forward any application proposing any changes to the OATT between now and when it is transitioned to IESO Nova Scotia, including if NS Power files a general rate application, then NS Power is directed to more fully consider the issues raised by Renewall in that application.

[643] As a final point, the Board notes that Renewall may have been able to raise its concerns about the relationship between the cost-of-service study and the OATT earlier had it had access to information that was not confidential but was only provided in the confidentially filed Excel files marked as Exhibit N-17(C)(i) SR-01 Attachment 1 and Attachment 2. Portable document format (PDF) versions of these files were only provided after the hearing in response to Undertaking U-4. While the Board prefers Excel files with intact formulae when available, if there is confidential information in those files, PDF

versions of those files with appropriate redactions of confidential information must be filed in all cases. NS Power must ensure it does so in all future matters before the Board.

3.9 Rate Design

[644] In its application, NS Power did not propose to introduce new concepts or materially change the design of any of its rates. The parties to the settlement agreement accepted the changes to tariff language and the updating of charges that NS Power proposed. For the most part, other parties raised no concerns about these matters in the evidence or submissions filed with the Board. To the extent not otherwise addressed in this decision or not otherwise requiring changes due to directions provided in this decision, the Board accepts these items as filed.

3.9.1 Innovation

[645] In NSEB IR-132, NS Power was asked to describe any work it has done to develop new or innovative rate designs to leverage more granular data from Advanced Metering Infrastructure (AMI) meters, promote efficient use of system resources, or address emerging or anticipated electricity and energy market changes due to decarbonization, decentralisation of energy resources, or other factors. In its response, NS Power said it was continuing to develop innovative rate structures through several initiatives and remains committed to developing rate designs that promote efficient use of system resources and respond to evolving market dynamics.

[646] NS Power noted that AMI infrastructure was instrumental in supporting both cost-of-service studies and ongoing pricing innovation work. NS Power referenced its time-varying pricing (TVP) program and the development of customer energy management systems to provide customers with tools and information to better understand their energy use and evaluate rate options that may be suitable for their usage

patterns. NS Power also noted that it expanded its TVP program to include a multi-unit residential building time-of-use pilot tariff. It said it also supports programming through the provision of AMI data to EfficiencyOne (E1) for demand side management activities and demand response programming. NS Power also cited its work with Port Hawkesbury Paper to design a rate to both provide service to that customer and leverage the characteristics of that customer's energy use to benefit the system.

3.9.1.1 Findings

[647] The Board accepts that NS Power is engaged in appropriate activities relating to the development of new rate designs. However, the Board believes that more can be done and encourages NS Power to do so. For example, while NS Power refers to the development of customer energy management systems as providing tools and information to customers to better understand their energy use and evaluate rate options that may be suitable for their usage patterns, there are not many rate options for many customers to choose from. The Board is also concerned that NS Power's outdated customer information system and the recent cyber attack have or will impede its progress in this area in the short term. The Board notes, for instance, that the TVP program was effectively suspended for the 2025/2026 winter season due to the company's inability to access data after the cyber incident.

[648] As Bonbright notes, the characteristics of a sound rate structure should include designs that are dynamically efficient in promoting innovation and responding economically to changing demand and supply patterns, discourage wasteful use of service and promote all justified types and amount of use. In the context of the energy transition, these characteristics of rate design should be a focus.

3.9.2 Residential and Small General Customer Charges

[649] In its last general rate application, NS Power proposed to increase customer charges for the domestic service and small general customer classes to align those charges with costs under its cost-of-service study. Other parties in the proceeding expressed some concerns about that proposal and, in the settlement agreement in that matter, customer charges for these classes were set at 75% of the amounts proposed. In the present proceeding, NS Power proposes to increase these customer charges in the same proportion as the increases in the smoothed non-fuel cost revenues for these customer classes, as set out in Figure 13-1 in its application:

Figure 13-1 – Proposed Increases to Customer Charges

Customer Class	Current Rate (\$)	Proposed Rate (\$) 2026	Proposed Rate (\$) 2027
Domestic Service	19.17	20.24	21.38
Small General	21.28	22.16	23.07

[Exhibit N-3, p. 81]

[650] In its response to NSEB IR-133, NS Power also calculated the customer charges that would result from a direct use of customer costs under its cost-of-service study. The results, which are reproduced below, also showed the offsetting impact on the proposed energy rates to maintain the required recovery of costs in the rates set for these customers:

Domestic Service Tariff				
	Capped Customer Charge	COSS-based Customer charge	Variance	Percent Variance
2026				
Standard Rate				
Customer Charge (\$/month)	\$20.24	\$29.32	\$9.07	45%
Energy Charge (cents/kWh)	18.349	17.306	(1.043)	-6%
Smoothed Rate				
Customer Charge (\$/month)	\$20.24	\$29.32	\$9.07	45%
Energy Charge (cents/kWh)	18.454	17.411	(1.043)	-6%
2027				
Standard Rate				
Customer Charge (\$/month)	\$21.38	\$30.25	\$8.88	42%
Energy Charge (cents/kWh)	19.335	18.310	(1.025)	-5%
Smoothed Rate				
Customer Charge (\$/month)	\$21.38	\$30.25	\$8.88	42%
Energy Charge (cents/kWh)	19.216	18.191	(1.025)	-5%

Small General Tariff				
	Capped Customer Charge	COSS-based Customer charge	Variance	Percent Variance
2026				
Standard Rate				
Customer Charge (\$/month)	\$22.16	\$31.98	\$9.82	44%
Energy Charge (First 200 kWh) (cents/kWh)	18.918	17.840	(1.078)	-6%
Energy Charge (Additional kWh) (cents/kWh)	17.089	16.208	(0.881)	-5%
Smoothed Rate				
Customer Charge (\$/month)	\$22.16	\$31.98	\$9.82	44%
Energy Charge (First 200 kWh) (cents/kWh)	19.053	17.975	(1.078)	-6%
Energy Charge (Additional kWh) (cents/kWh)	17.224	16.343	(0.881)	-5%
2027				
Standard Rate				
Customer Charge (\$/month)	\$23.07	\$33.28	\$10.21	44%
Energy Charge (First 200 kWh) (cents/kWh)	20.100	18.984	(1.116)	-6%
Energy Charge (Additional kWh) (cents/kWh)	18.074	17.163	(0.911)	-5%
Smoothed Rate				
Customer Charge (\$/month)	\$23.07	\$33.28	\$10.21	44%
Energy Charge (First 200 kWh) (cents/kWh)	19.951	18.835	(1.116)	-6%
Energy Charge (Additional kWh) (cents/kWh)	17.925	17.014	(0.911)	-5%

[Exhibit N-27, PDF pp. 550-551]

[651] As can be seen in the foregoing tables, keeping lower customer charges necessarily increases energy charges, and vice versa. Customers in these classes that use higher than average amounts of energy pay more when customer charges are lower and less when customer charges are higher. The opposite is true for customers who use less energy than the average customer in the rate class. The extent to which the energy rate is higher or lower also affects the cost effectiveness of energy efficiency and demand response programs for these customers. It may also affect the choice of alternatively designed rates.

3.9.2.1 Findings

[652] The Board accepts that there may be legitimate arguments for not setting customer charges for these classes directly from the cost-of-service study. However, given the potential impacts that the setting of customer and energy charges may have on intra-class cost shifting, efficiency and demand response, and the consideration of alternatively designed rates, there should be a principled basis for doing so. The extent of the variance should not be arbitrary. While increasing these charges based on the average increase in non-fuel revenues for these customers might be convenient, it is not clear to the Board that costs classified as customer-related under the cost-of-service study necessarily change at the same rate as other costs.

[653] The Board directs NS Power to consider this matter and address it in more detail in its next general rate application. The Board notes that the method for classifying distribution system costs to customers also affects this issue. Indeed, in the Ontario Energy Board cost allocation review staff discussion paper submitted as Exhibit N-63, it appears to be suggested that fixed monthly customer charges could conceivably be considered within a range of reasonableness bounded by a floor set using the basic

customer method and a ceiling using either the zero-intercept or minimum system methods (p. 14).

3.10 Miscellaneous Charges and Regulations

3.10.1 OATT

[654] NS Power's Open Access Transmission Tariff (OATT) includes terms, conditions and rates for Transmission Services and Ancillary Services. It also includes operating agreements under which service will be provided, and the Standards of Conduct which govern the treatment of transmission system and market information within NS Power. The OATT was initially approved in 2005 and amended on June 10, 2016.

[655] In this application, NS Power updated OATT rates to reflect changes in revenue requirement, driven by changes in generation and transmission asset mix and costs, and changes in system usage since the last update in the 2023-2024 GRA.

[656] NS Power proposed amending the OATT methodology based on consultation in the 2024 Cost of Service proceeding. Those amendments include basing OATT rates on forecasted test year usage instead of historic usage, and basing transmission rates under schedules 7, 8 and 10 on transmission-related revenue requirement as determined in Cost-of-Service studies instead of on formulaic calculations. NS Power stated those proposed amendments will help eliminate transmission revenue requirements differences used for the OATT and bundled service rates.

[657] NS Power also proposed a modification to the determination of reactive power usage, applied in rate calculations under Schedule 2, from a single system peak

hour to a multi-hour peak based on the 97th percentile usage of Reactive Power from generation.

[658] The 2023-2024 GRA (M10431) Board Order included the following directives regarding the OATT and capacity-based ancillary services (CBAS):

- To explore options with Northern Power Coordinating Council (NPCC) about alternative treatment of interruptible loads and to file its analysis of cost implications in the next GRA;
- Explore, prior to the next GRA, alternative treatment of the -16 MW requirement in Automatic Generation Control and to demonstrate that it is not double charging transmission customers;
- Demonstrate, no later than in its next GRA, how the spinning reserve and 10-minute supplementary reserve utilization for Wreck Cove is represented in its CBAS calculations; and
- Provide a more fulsome explanation, no later than in its next GRA, to justify its position to exclude combustion turbine (CT) units from its costing of 30-minute supplemental reserve for the CBAS calculations.

NS Power addressed those directives and incorporated certain changes based on its review of those issues.

[659] Ancillary Services are support services required to enable the transmission system to transmit energy while maintaining reliable operation of the system. They range from actions needed to enable and balance a transfer of electricity between buyer and seller, to services needed to maintain transmission system integrity and reliable operation at designed voltages and frequency.

[660] The OATT requires NS Power, as the Transmission Provider, to make all Ancillary Services available to all Transmission Customers, so it must be able to procure adequate generation resources to do so. Transmission Customers can purchase each of the Ancillary Services from the Transmission Provider, or they can self-supply the capacity-based ancillary services or purchase them from a third party.

[661] The capacity-based ancillary services include Regulation and Frequency Response Service, as well as Operating Reserves, which include 10-minute spinning reserve, 10-minute supplemental reserve, and 30-minute supplemental reserve. NPCC defines the requirement for Operating Reserves in the Maritimes Control Area. At all times, NS Power must have 32 MW of spare capacity available from units already online (spinning reserve), 136 MW of capacity (or load reduction) that can be made available within 10 minutes (supplemental reserve), and an additional 50 MW of capacity (or load reduction) that can be made available within 30-minutes (supplemental reserve).

[662] Regarding treatment of interruptible load, NS Power stated that LIIR interruptible load is not suitable for day-ahead reserve planning, but it does provide value when used in real time to manage through capacity scarcity events. Under the settlement agreement, it was agreed that the costing approach for 2026 and 2027 will utilize 50% of the estimated average hourly demand of LIIR interruptible load as 10-minute operating reserve on a day ahead basis. This reduces the required 10-minute supplemental reserve of 136 MW by 35 MW, to 101 MW, for pricing purposes of that service. Accordingly, LIIR interruptible load equipped with Telemetry and Control will be included in managing real-time 10-minute reserve at all times, not just when it is not available from generation resources.

[663] On the issue of alternative cost treatment of the -16 MW requirement in regulation service, as its own Balancing Authority, NS Power must balance load and generation within the province, measured by the Area Control Error on the Nova Scotia-New Brunswick (NS-NB) tie-line. To maintain transmission security limits, Area Control Error on the NS-NB tie-line must be closely controlled. Area Control Error changes can affect the stability of the transmission network, so adequate regulation capability is needed to manage deviations in net load and variable generation to ensure system stability. NS Power's analysis of net load-variable generation deviations in the NS Balancing Area determined that it needs +/- 16 MW of regulation capability to adequately manage the system with the current level of variable generation and load behaviour.

[664] NS Power noted that when a dispatchable generator is operating at or near minimum generation limits, it bottoms out on its ability to provide Regulation Down (Reg Down) service (i.e., the -16 MW component). That generator's capacity would still be supplying customer energy needs, but it cannot offer Reg Down service because its output cannot be lowered any further. NS Power submits that capacity for Reg Down service must be set aside separately from capacity used to serve the energy needs of load customers. Since that set-aside capacity is incremental to the capacity allocated to serving energy, NS Power stated that its cost must be recovered through the prescribed costing methodology of the OATT. NS Power maintains that the current costing methodology adequately and fairly allocates capacity costs to the provision of Regulation Service and submits that there is no double-counting of capacity.

[665] Regarding NS Power's treatment of spinning reserve and 10-minute supplementary reserve utilization of Wreck Cove in its CBAS calculations, NS Power

determined that capping Wreck Cove at a 32 MW capacity contribution (the current requirement for Spinning Reserve) produces a 10-Minute Spinning Reserve weighted annual cost of \$139.69/kW, which is immaterially different by 0.2% as compared to the \$139.98/kW rate used in the 2023-2024 GRA. NS Power has capped the contribution of Wreck Cove to the 32 MW Spinning Reserve requirement in the calculation of the rate for Spinning Reserve service.

[666] The issue of including less expensive CTs in the CBAS costing calculations for 30-minute supplemental reserve was also reviewed by NS Power. It noted that the power system is experiencing a transformation from a system with large base-loaded, dispatchable generators to one with a large and growing penetration of variable renewable energy resources. With that understanding, NS Power conducted an analysis of historical day-ahead dispatch plans for the years 2021 to 2023 and determined that CTs were dispatched to fulfill approximately 35% of the 30-Minute Supplemental Reserve requirement each hour.

[667] Given this change, NS Power adjusted the cost allocation for 30-Minute Supplemental Reserve to account for the contribution that CTs make in the provision of 30-Minute reserve, as per its analysis, and implemented the adjustment in this GRA.

3.10.1.1 Findings

[668] As noted above, OATT rates have been updated to reflect changes in the generation and transmission asset mix and costs, and changes in system usage since the last update in the 2023-2024 GRA. NS Power also amended the OATT methodology based on consultation in the 2024 Cost of Service proceeding.

[669] In addition, NS Power addressed the Board’s hearing order directives from the 2023-2024 GRA (M10431) pertaining to the OATT and capacity-based ancillary services, and incorporated certain changes based on its review of those issues.

[670] The Board approves the OATT amendments as proposed by NS Power in this matter.

3.10.2 AMI Opt-Out Fee

[671] NS Power has requested Board approval to implement an opt-out fee for customers who have not agreed to the installation of an AMI smart meter for remote meter reading and billing purposes. Capital and operating costs associated with the AMI facilities are embedded in NS Power’s revenue requirement and those costs are being recovered from all customers, including opt-out customers.

[672] NS Power’s proposed monthly opt-out charges are provided in Table 1.

Table 1 – Proposed Schedule of AMI Opt-out Fee Monthly Charges for 2026 and 2027

Standard Customer Meter Read Frequency	Proposed Opt-out Customer Meter Read Frequency	Proposed Opt-out Charge	
		in 2026	in 2027
Bi-monthly (6 times per year)	Semi-annually (twice per year)	\$3.81 per month	\$4.47 per month

Standard Customer Meter Read Frequency	Proposed Opt-out Customer Meter Read Frequency	Proposed Opt-out Charge	
		in 2026	in 2027
Monthly (12 times per year)	No change (12 times per year)	\$22.89 per month	\$26.79 per month

[Exhibit N-8, Appendix 13A, pp. 3-4]

[673] To reduce monthly charges for opt-out customers, NS Power proposes to conduct semi-annual meter readings for customers whose meters are currently read bi-monthly (i.e., Domestic and Small General classes), and to continue monthly readings for

customer classes that include a monthly demand charge (i.e., General, Large General, Small Industrial, Medium Industrial, Large Industrial, and the Municipal Tariff). NS Power estimated that the reduced frequency of manual meter readings will lower the total required meter reading hours by 64% and result in a total estimated cost savings of \$1.2 million over 2026 and 2027.

[674] When addressing the option of customer-submitted meter readings, NS Power dismissed that option as “not a reasonable proxy for NS Power meter reads”. It suggested it would be challenging for customers to provide accurate readings and that it could result in intentional misreporting:

AMI meters are digital; they cycle through various data points, which make it challenging to accurately capture consumption readings and increase the likelihood of unintentional errors in customer-submitted readings. In 2024, approximately 177 customer accounts submitted a post card or photo meter read; this represents less than 1 percent of the 18,140 customers that have opted out of AMI meters. Customer-submitted meter readings can also result in intentional misreporting, particularly in the absence of established regular and systematic utility-led verification processes. While Regulation 5.1 allows for customer-submitted readings, NS Power still needs to receive, verify, and process these readings, along with handling disputes and correcting errors.

[Exhibit N-8 Appendix 13A, p. 8]

[675] In response to Board IR-148, NS Power stated that in 2024, there were 16 postcard meter submissions and 161 photo meter submissions; however, it does not track if those submissions provided incorrect readings. When asked if instructional material is, or can be, available to assist customers to correctly record their AMI digital meter readings, NS Power stated:

Instructional material is currently available on the Company’s website (FAQ| Nova Scotia Power). NS Power plans to update its current self-report online forms which augment the existing content. This is part of the MyAccount restoration work being conducted in response to the cybersecurity incident and is expected to be completed in 2026.

[Exhibit N-27, IR-148, p. 2]

[676] Board IR-148 also asked NS Power if it had the ability to detect billing anomalies that might indicate incorrect meter readings (whether intentional or not). NS

Power said it has the ability to identify customer bills that exceed a pre-defined dollar-value threshold set for any particular rate code. This issue was further canvassed during the hearing:

Q. I think the last question I asked was -- it was in response to your response, which I understood to indicate that there wasn't a specific threshold that was set once for the entire rate code, that it was more, to use your words, nimble than that. And so I asked whether each individual customer account had a threshold set for it.

A. (Williams) Yes. I don't believe it's a specific threshold that's established and held static, if you will. My understanding is that it's -- the system will recognize when there's higher energy usage than would be expected or typical, and I believe that that occurs through the "My Energy Insights" program.

Q. So this response refers to a pre-defined dollar value threshold. What does that mean?

A. (Williams) So again, my understanding is that it's pre-defined through the system in terms of the historical usage, that it wouldn't be the same dollar value for every customer.

[Transcript, January 12, 2026, pp. 968-969]

[677] On page 9 of Appendix 13A, NS Power stated that "Opt-out meter reading is based on the forecast incremental cost to serve opt-out customers, and informed by the company's actual experience with opt-out costs". On page 6 of that Appendix, NS Power stated that it "has explored all reasonable options to minimize or eliminate the proposed fee".

[678] Exhibit N-8, Appendix 13C shows that in 2024, there were 18,140 opt-out customers. In that year, NS Power received 650 inbound calls from opt-out customers which resulted in Customer Care expenses of \$10,000. The opt-out development chart presented in Exhibit N-4, PR-02 Attachment 1 shows an estimated 18,819 opt-out customers for 2025, Customer Care Calls totalling 13,333, and Customer Care cost for opt-out only as \$144,863. When questioned during the hearing about this large variance, NS Power stated that the 2025 projection was based on 0.71 calls annually per opt-out customer since NS Power assumed there would be a much greater influx of calls after

the actual meter reading frequency for domestic customers changes from six readings per year to two readings per year (i.e., from bi-monthly to semi-annual). By comparison, the actual number of calls per opt-out customer in 2024 was only 0.036, which is 20 times lower than the estimate NS Power assumed for 2025.

[679] Also, during the hearing, NS Power was questioned whether opt-out meter reading activity was separated from other manual reading activity. NS Power stated that it hired 100 meter readers to manually read meters when communication between AMI meters and its billing system was disrupted by the cyber incident. It further confirmed that those contracted meter readers were reading opt-out meters:

Q. Are contracted meter readers also reading opt-out meters?

A. (Williams) Yes.

Q. They are?

A. (Williams) Yes.

...

Q. And the meter readers are reading opt-out meters. Are they doing the other general work as well? Were they hired on to do the cyber work?

So because presumably you had reader meters just to do opt-out meters. Are they also reading the cyber-related meters -- cyber reach?

A. (Williams) So we would have a limited number of meter readers on staff for those opt-out meters. I can't say definitively at certain points of time whether there's delineation being drawn definitively on -- to that level of detail...

[Transcript, January 9, 2026, pp.898-899]

3.10.2.1 Findings

[680] The Board has several concerns with NS Power's request to implement AMI opt-out fees at this time. Based on the responses provided during the hearing, it appears that meter reader costs associated with opt-out meters and those associated with cyber related manual meter readings are insufficiently delineated to accurately assess opt-out

fees. Also, despite NS Power's statement that opt-out costs are informed by actual experience, development of those costs appears to be based on certain questionable forecast assumptions. For example, projecting a 20-fold increase in customer care costs and opt-out calls after fees are implemented raises further concerns.

[681] Regarding potential self-reporting options for opt-out customers, NS Power has dismissed that option by suggesting it is too challenging to accurately read digital meters or that customers might intentionally (or unintentionally) submit incorrect readings. Those statements were made despite acknowledging that numerous photo meter readings have been accepted by NS Power and meter reading instructional material is currently available on the company's website.

[682] Regarding the possibility of intentionally or unintentionally submitting incorrect readings, the Board notes that NS Power currently has set certain bill thresholds against which individual bills are reviewed for anomalies, such as high bills. NS Power also stated it intends to explore additional criteria to identify bill exceptions through its Customer Information System modernization initiative. The Board questions whether NS Power has given sufficient consideration to establishing bill thresholds which could flag photo or postcard reading submissions that may be incorrect. Perhaps advancements in technology, such as artificial intelligence, could alleviate that concern.

[683] NS Power appears reluctant to consider providing opt-out customers with options such as self-reporting which could facilitate maintaining bi-monthly readings, or perhaps might require only a single manual reading for verification purposes. NS Power's meter reading regulation 5.1 states that the company may adopt a postcard meter reading system in rural areas and may consider postcard meter readings to be actual meter

readings. That regulation currently states that “Notwithstanding the foregoing, an actual reading must be taken by the Company at least once within a twelve-month period for meters which are read bi-monthly and once within a six-month period for meters which are read monthly”. NS Power has not provided any reasonable justification why a similar option could not be available to opt-out customers.

[684] The Board is not persuaded that implementing semi-annual or monthly manual meter readings and applying opt-out fees is the only option that should be made available to customers. Based on the concerns noted above, the Board denies NS Power’s request to impose opt-out fees or to amend related regulations at this time. NS Power is directed to address this in a compliance filing.

3.10.3 Revised Fees and Regulations

[685] In its application, NS Power proposed revisions to its Schedule of Charges, such as for connection, reconnection, returned cheques, installation of recording equipment, contribution for three-phase service, load research charges, and pole attachment fees. Subject to the Board’s findings above relating to the AMI opt-out fee, the Board approves these revisions.

4.0 OTHER ISSUES

4.1 Demand Side Management Cost Recovery Rider

[686] In this GRA, NS Power proposed changes to the methodology for calculating the Balance Adjustment (BA) but did not propose changes to the Demand Side Management (DSM) rider amounts for 2026 or 2027. NS Power filed its DCRR application for recovery of the 2026 DSM expenses, using the current DCRR framework, on October 22, 2025 (M12521). The Board’s Interim Order of December 22, 2025,

approved continuation of the 2025 DCRR charges commencing January 1, 2026, until further order of the Board in that matter, or as part of NS Power's ongoing general rate application. The 2026 DSM expenditure level was set at \$63.75 million by legislation and in this GRA, NS Power assumed the same expenditure level for 2027. Similarly, it assumed continuation of the DCRR amounts for 2026 or 2027.

[687] In proposing the change to the BA methodology, NS Power's response to Board IR-143 referenced the flexibility for E1 to re-allocate DSM expenditures between rate classes within a DSM term, and recent legislative changes which prescribe five-year DSM terms beginning with the 2027-2031 DSM Plan. It noted that the end-of-term true-up under the current framework might result in large variances to be collected or refunded through the DCRR. The new proposal would extend the recovery or refund period for end-of-term variances, which is expected to reduce the volatility in rate impacts of DSM expenditure reallocations and better reflect the multi-year nature of DSM planning and spending.

[688] The proposed DCRR framework adds a BA₂ component to the BA to reconcile, by rate class, the differences between E1's approved and actual DSM expenditures following the completion of the prior DSM Plan term. Under the current DCRR framework, those variances would be trued up and recovered over one or two years. The proposed BA₂ allocates those variances evenly over a four-year recovery period, beginning in year two of the following term, reducing the volatility in rates driven by E1 expenditure decisions.

[689] In addition, the proposed framework will allocate 100% of the DSM costs to classes in accordance with DSM program spending. This is intended to align with feedback and the recent COSS. In Matter M12521, NS Power stated:

NS Power is proposing to amend the allocation of the Demand Side Management (DSM) Rider. Currently, the DSM Rider is allocated as 75 percent to the cost of programs undertaken for the rate class, with the remaining 25 percent allocated to the system benefit of the programs. Based on stakeholder feedback, NS Power is proposing to remove the allocation to system benefit, so that 100 percent of DSM Costs will be allocated to classes in accordance with program spending. This will more accurately align cost responsibility with the direct beneficiaries of DSM program spending. The 25 percent allocation to system benefit that was used previously was an arbitrary number, as discussed in NS Power's response to CA DR-87, which includes an analysis demonstrating that very little system benefit is provided by the DSM Rider. The change of allocation to remove system benefit, and allocation of the DSM Rider 100 percent to program costs, will also serve to place NS Power in better alignment with other jurisdictions and allow for simplification of the COS treatment of these costs. This is also described in more detail within the Elenchus Report.

[M12521, Exhibit N-1, p. 5]

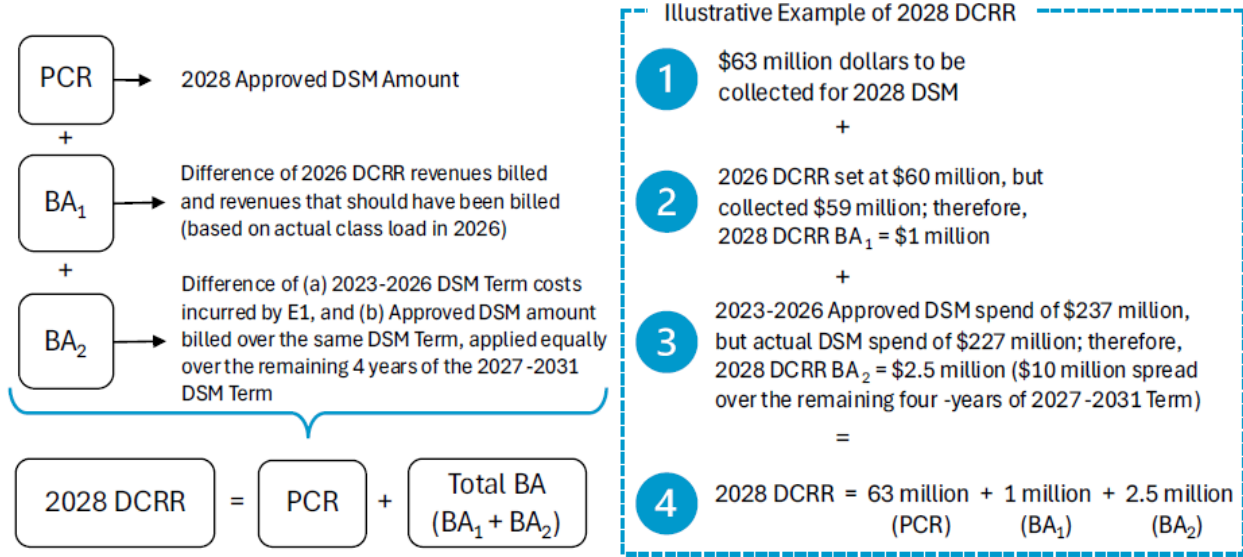
[690] The proposed BA methodology will include the annual volume variance adjustment (BA_1), calculated by class, for the difference between the actual revenues billed and the forecast revenues for the previous calendar year. That component will be applied on a two-year lag. An End of Approved DSM Term Adjustment (BA_2) will also be included, which trues up the differences by class between the approved and actual spending over the most recent DSM term (period governing the supply agreement). That amount will be calculated in the first year of the next DSM term and will be applied over the four following years of the DSM term. The BA will reflect the annual volume variance adjustment each year and the DSM term adjustment after the conclusion of each term.

[691] In its response to Board IR-143, NS Power provided a graphic of the proposed framework:

Proposed DCRR Framework

If approved, the proposed DCRR framework would be in effect during the 2027-2031 DSM Term.

For example, the 2028 DCRR would include:



[Exhibit N-27, NSEB IR-143, p. 2]

[692] In the example, BA₁ reconciles volume-based variances and BA₂ adds a DSM expenditures-based reconciliation mechanism. Variances following the end of the 2023-2026 DSM term would be calculated in 2028 and allocated across the remaining four-years of the 2027-2031 DSM term (i.e. 2028, 2029, 2030, and 2031).

4.1.1 Findings

[693] The Board’s Interim Order in Matter M12521 approved continuation of the 2025 DCRR charges commencing January 1, 2026, until further order of the Board in that matter, or as part of NS Power’s GRA. In this current matter, NS Power is not proposing changes to the DSM rider amounts for 2026 or 2027, but it is proposing changes to how the Balance Adjustment (BA) is calculated. Updated values for the rider amounts in 2026 will be approved in a final order in Matter M12521. Rider amounts for 2027 will be determined in a subsequent DCRR annual application.

[694] The Board notes that the proposed DCRR tariff amendments are intended to address potential end-of-term variances, as well as variance associated with E1's flexibility to re-allocate DSM expenditures between rate classes within a DSM term. Since those amendments are expected to improve the DSM cost recovery process, the Board approves the amended DCRR tariff.

4.2 Storm Cost Recovery Rider

[695] During the 2023-2024 GRA process, participants raised a concern about the asymmetrical nature of the Storm Cost Recovery Rider (SCRR). The current SCRR allows for NS Power to apply to recover Level 3 and 4 storm costs it incurs above those amounts included in the approved revenue requirement. However, it does not provide a mechanism by which funds could be returned to customers if the forecast amounts included in revenue requirement were not fully spent.

[696] In this application, NS Power is requesting approval to continue the SCRR as a pilot during 2026 and 2027. It is also asking that the SCRR be in place on a symmetrical basis, which would allow it to recover Level 3 and 4 storm OM&G restoration costs above those included in revenue requirement, and for any underspend of such costs to be returned to customers in each year.

[697] The key elements of the proposed SCRR are the same as what was approved in the 2023-2024 GRA, but with the added symmetrical component. It is worthy to note that storm costs eligible to be included in the Storm Cost Recovery Rider in any given year cannot exceed 2% of that year's forecast retail revenues. Eligible storm costs in excess of the 2% cap will be deferred to the subsequent year's SCRR.

[698] A new term proposed to be included in the amended SCRR states:

However, if the actual Level 3 and Level 4 storm costs are below the amount of Level 3 and Level 4 storm costs included in NS Power's revenue requirement as approved by the NSEB, the Company will track any underspend in a SCRR Customer Account where it will be accumulated until a threshold amount of \$2.5 million is reached or a balance has been held for three consecutive years, upon which time NS Power will make an application to return the underspend amount to customers.

[Exhibit N-4, PR-01, Attachment 01V, p.1]

[699] The 2026 and 2027 values for the SCRR rider are zero but NS Power's forecast expenditures for OM&G storm restoration costs in 2026 and 2027 are:

Figure 13-2 – Storm Restoration OM&G Costs (Levels 1-4)

	Level 1 & 2 (\$ million)	Level 3 & 4 (\$ million)
2026	9.6	10.1
2027	9.8	10.3

[Exhibit N-3, p. 85]

[700] Level 3 and 4 forecasts are similar to the previous three years, but Level 1 and 2 forecasts are more than 30% above the amounts in each of the previous three years.

4.2.1 Findings

[701] As noted above, the 2026 and 2027 values for the SCRR rider are zero. The proposed amendments are expected to correct the unbalanced asymmetrical nature of the current version of the rider. The amendments should also minimize administrative burden that could result from requiring annual applications to refund small amounts of underspent funds. Recognizing these enhancements, the Board approves the proposed version of the SCRR to continue as a pilot during 2026 and 2027.

4.3 Climate Change Adaptation Plan

[702] The NSUARB, in its decision in NS Power's last general rate application, directed the utility to develop and file a climate change adaptation plan in consultation with interested parties:

[339] The Board also notes that in its response to Board IR-171 [Exhibit N-69], NS Power identified a number of steps it is taking to address the challenge of a changing climate, as well as to meet increasing expectations from customers to mitigate risks from severe weather events. The Board is aware that utilities in other jurisdictions have developed formal climate change adaptation plans. For example, Hydro-Québec recently released a Climate Change Adaptation Plan for 2022-2024. Additionally, the Board understands that organizations like Electricity Canada and the Electric Power Research Institute have developed guidance documents for utilities to develop such plans and climate change adaptation strategies.

[340] It is not clear to the Board whether the items identified by NS Power in its response to NSUARB IR-171 are part of a formalized Climate Change Adaptation Plan adopted by the Company. The Board considers that the implementation of such a plan, through a consultative process, may be useful in demonstrating the prudence of storm restoration costs in Storm Rider cost recovery applications, would engender confidence in such a rider if NS Power seeks to implement one after the period covered by the GRA Settlement Agreement, and would enhance NS Power's capital expenditure processes and integrated resource planning. As such, NS Power is directed to engage in a consultative process to develop a Climate Change Adaptation Plan to be filed with the Board no later than the end of 2025. As with the COSS and Line Loss Study discussed later in this decision, the Board approves the deferral of the costs of developing this plan for recovery through rates after NS Power's next general rate application.

[2023 NSUARB 12]

[703] NS Power filed a Climate Change Adaptation Plan and Wildfire Mitigation Plan in this proceeding [Exhibit N-5, Appendix 3B and Appendix 3C]. NS Power said it did have a climate adaptation plan before its last general rate application but noted the directive required a consultative process to develop a formal plan. It said the consultation process primarily relied on engagement with the Climate Adaptation Leadership Program and a technical conference with intervenors held before formally filing the plan as part of this general rate application.

[704] The essence of NS Power's Climate Change Adaptation Plan involves the collection and analysis of climate data and feeding this into its existing asset management system. While the plan references the identification of climate related vulnerabilities for

operational assets, it does not set out much detail about these vulnerabilities, potential mitigation measures to address them or the timelines involved. NS Power addressed this at the hearing:

Q. So why doesn't this plan sort of identify what this valuable information is that you've gathered about the vulnerabilities and identify the potential mitigation measures and the timelines for the Board and interested parties? It all seems to be under the hood, as it were, in the asset management system. Why isn't it included transparently in the plan?

A. (MacIntosh) So these factors evolve over time. The company does deploy systems asset management mechanism system, which includes the input of climate risks in our risk profiles, as well as the Climate Adaptation Management System which house those. But I appreciate your point that there are, I'll say, thousands of lines of associated data that is included in our climate modelling that's assigned to these assets. So we try to provide a sample of that inside this Climate Adaptation Plan, which is really trying to outline the methodology Nova Scotia Power used to incorporate these climate factors into our plan processes. But appreciate the point again that there's much more data that's associated with this and how those are assigned to our specific asset classes.

[Transcript, January 12, 2026, pp. 1030-1031]

[705] Hydro-Québec's Climate Change Adaptation Plan (2022-2024), entered in this proceeding as Exhibit N-62, was also the subject of questions presented to NS Power's witnesses at the hearing. As outlined in the Hydro-Québec plan, that utility developed its plan in two phases. The first phase consisted of compiling a list of climate change risks that could affect assets and the second phase focused on establishing action areas, identifying potential adaptation measures and determining what actions to take to mitigate risks. NS Power appeared to agree that while it undertook a process comparable to the first phase of the development of the Hydro-Québec plan, the NS Power plan does not present information consistent with the second phase. NS Power maintains that its plan presents the method it has been and will continue to use to identify and undertake climate adaptation measures.

[706] Likewise, the Hydro-Québec plan included "fact sheets" that describe climate related impacts on utility activities or assets, provide further information for

context, list the actions to address the particular issue and the potential adaptation measures, and identify any challenges to overcoming mitigating those risks. NS Power's plan has no similar information. However, NS Power said this information is in its climate adaptation management system, a program database, and could be provided.

4.3.1 Findings

[707] The fact that NS Power compiles and analyzes climate data and uses this information in its asset management systems is positive. However, NS Power's Climate Change Adaptation Plan is more of a process than a plan per se. It also focuses specifically on assets and is less directly connected to its other resources and operations.

[708] As noted above, part of the NSUARB's intention in directing the development of a climate change adaptation plan was to assist in demonstrating the prudence of storm restoration costs, engender confidence in NS Power's storm cost recovery rider and enhance its capital expenditure and integrated resource planning processes. The Board is concerned that what NS Power has presented has not and will not fully achieve these objectives.

[709] NS Power's asset management processes were recently reviewed (2024 NSUARB 59) and there were only limited concerns raised about them, which the utility has taken steps to address. While these processes may very well be reasonable and adequate, they are not very transparent.

[710] Further, it is not apparent to the Board that regular intervenors in proceedings involving NS Power were included in the development of NS Power's plan. What was described by NS Power in the evidence in this proceeding was a more modest level of consultation with those parties than the Board would have expected.

[711] The Board finds that NS Power's Climate Change Adaptation Plan would be enhanced if, like the Hydro-Québec plan, it included information to more clearly and transparently describe and provide context around potential or anticipated climate related impacts on utility resources, activities and assets; actions to address issues identified; potential and likely adaptation measures; and any challenges to mitigating risks. NS Power is directed to file a revised Climate Change Adaptation Plan with the Board adding these elements no later than October 1, 2026.

4.4 Lingan Unit 2 and Trenton Unit 5

[712] In its general rate application, NS Power assumed sustaining capital expenses of \$20,829,182 at Lingan 2 during the 2026-2027 test period, including \$18,433,591 in 2026 and \$2,395,591 in 2027 (Bates White IR-11, Attachment 1). At the hearing, NS Power stated that, based on the latest information, the forecast sustaining capital costs for Lingan 2 are now projected to be deferred from 2026 to 2027.

[713] Moreover, it forecasts OM&G costs of \$8.9 million at Trenton Unit 5 and Lingan Unit 2 during the test period due to a change in the retirement assumptions for these coal units and increased hours of operation [Exhibit N-6, Appendix 7C, PDF p. 63]. The OM&G costs include increased labour, contracts and materials resulting from the need for these units to remain available for dispatch until at least 2027 for Lingan 2 and 2029 for Trenton 5 [Exhibit N-23, GT IR-26]. The increased OM&G labour costs for these two coal units represent an increase of 49 FTEs in 2026 compared to 2024CR [Exhibit N-27, NSEB IR-42, pp. 2-3].

[714] In its evidence, Bates White noted that the forecast sustaining capital costs at Lingan 2 marks a departure from recent experience at the coal unit and represents a relatively "substantial cost" for the modest amount of energy the unit is forecast to provide

in the test period. It recommended that the proposed large increase in sustaining capital costs for Lingan 2 “be supplemented with additional narrative support” by the company.

[715] In response to questions from Board Counsel and the Board, NS Power stated that until now the company has managed the risks of operating Lingan 2 through asset management techniques, including “operational restrictions and enhanced monitoring”. It said it has delayed major refurbishment work but now a complete turbine and generator refurbishment is needed to maintain the safe operation of the coal unit. It also noted that sustaining capital for Lingan 2 has been very low compared to other units. Failure to conduct refurbishment work could result in significant consequential damages.

[716] Jonathan MacIntosh, Director of Enterprise Asset Management for NS Power, testified that any capital projects for Lingan 2 will be “brought before this Board for approval in addition to its operating cost, so approving this GRA does not approve the Lingan Unit 2 capital”. However, he acknowledged in questioning by the Board that those costs are embedded in the proposed rates (Transcript, January 9, 2026, p. 694).

[717] NS Power stated that these coal units have been retained to serve customer load and provide system capacity, as required by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC) requirements. It explained the changes to the coal plant retirement timelines:

- (a) The retirement assumption for Lingan 2 changed in Q2 2024 following the completion of the 2024 Load Forecast (which had an increase of 108 MW in the forecast firm peak for 2024) and concurrent with the development of the 2024 10-Year System Outlook. The resource and capacity assessment developed for the 2024 10-Year System Outlook identified that due to the change in the load forecast it was necessary to extend the use of Lingan 2 until replacement firm capacity procured by IESO-NS came online. An updated retirement date of 2027 for Lingan 2 was provided in the 2024 10-Year System Outlook, which was submitted to the Board on June 27, 2024. The change in the forecast retirement date for Trenton 5 to 2027 was a finding of the 2023 Evergreen IRP. It was first reflected in the 2023 10-Year System Outlook, and is shown in subsequent reports. The decommissioning timeline for Trenton 5 was further updated in the 2024 Decarbonization Deferral Account (DDA) - 2024 Annual Report. The update in the 2024 DDA report reflects the need to maintain units available until reliable

operation of replacement generation has been established and that decommissioning activities are not expected to begin until after 2029.

[Exhibit N-23, GT IR-26, pp. 1-2].

[718] In a recent application for Lingan 2 sustaining capital costs, NS Power noted that IESO Nova Scotia is responsible for the procurement of fast-acting replacement generation, but “given the lead times seen across the industry for new combustion turbines, it is increasingly unlikely that the NSIESO’s procurement process will allow new fast-acting generation units to be online by Winter 2027-28” [Exhibit N-60, p. 2]. Accordingly, it is keeping Lingan 2 in cold reserve until the reliable operation of replacement generation is available. NS Power confirmed that it has expressed its concerns to IESO Nova Scotia about the latter’s procurement of fast-acting generation and its implications, including in relation to Lingan 2.

[719] In its closing submissions, the Department of Energy submitted that the Board assess the utility’s need for additional investment in Lingan 2 and to deny NS Power’s request for sustaining capital costs.

4.4.1 Findings

[720] NS Power’s firm capacity requirements in advance of 2030 continue to be the subject of review in several matters considered by the Board, including the Evergreen IRP Action Plan and Roadmap Update, the 10-Year System Outlook Report, the Load Forecast, the annual ACE Plan and The Path to 2030. The approval of sustaining capital costs for Lingan 2 is not an issue under review in this matter. While the Board is mindful of the concerns expressed by the Department of Energy and Bates White, NS Power’s request for sustaining capital costs will be considered in another proceeding. The 2026

ACE Plan matter (M12619) noted that the application will be filed as a subsequent submittal.

[721] OM&G costs of \$8.9 million are forecast at Trenton Unit 5 and Lingan Unit 2 during the test period. NS Power has demonstrated in various proceedings that Lingan 2 and Trenton 5 are required to maintain adequate capacity to serve customers, including keeping a planning reserve margin required by NERC and NPCC. These detailed proceedings have included the Evergreen IRP Action Plan and Roadmap Update, as well as the 10-Year System Outlook Report and the Load Forecast which are updated annually.

[722] The Board finds that the proposed OM&G costs for Lingan 2 and Trenton 5 are required to provide customers with safe and reliable service. They are also required to support compliance with important NERC and NPCC requirements. Accordingly, the Board approves the forecast OM&G costs for these units in the test period.

4.5 Rate Setting – Alternative Form of Regulation

[723] In its closing submissions the Nova Scotia Liberal Caucus urged the Board to exercise its statutory authority to move Nova Scotia toward a five-year rate plan that delivers stability, predictability, and fairness for ratepayers. Although the Liberal Caucus specifically referenced the Board's ability to approve multiyear rate applications under s.64A(2B) of the *Public Utilities Act* in its opening statement, more recent legislation provides more flexibility.

[724] The *Public Utilities Act* was amended in 2024 to allow the Energy Board to approve an application for a rate, toll or charge that is based on a method or technique the Energy Board considers appropriate, including an “alternative form of regulation” (s.

64(3)). This is consistent with language in the *Energy and Regulatory Boards Act* (s. 6(1)), which also provides a definition of “alternative form of regulation”:

Interpretation

2 In this Act, unless the context otherwise requires,

“alternative form of regulation” means a method of establishing just and reasonable rates, tolls, charges and tariffs by performance-based regulation, including earnings sharing, price caps, price indexing formulas, ranges of authorized rates of return and the increase, reduction or suspension of regulatory requirements, without regard to methods based strictly upon cost of service, rate base and rate of return;

[725] The possibility of implementing an alternative form of regulation was canvassed at the hearing and NS Power agreed that it was worthy of discussion. NS Power revisited this in its closing submissions:

NS Power agrees that multi-year and performance-based rate plans warrant consideration. In theory, these plans could assist with providing for more predictable rate increases and a better understanding for customers, but the practical reality of implementing such plans is a much more complicated endeavor where an improved regulatory regime is not a certainty. Consideration of such plans must include how they may work and may improve on the current regulatory regime, taking into account the vertically integrated nature of NS Power and the work needed to meet Nova Scotia’s 2030 decarbonization goals. Included in these considerations would also be the establishment of the IESO-NS and the extent to which it will alter (1) existing regulatory responsibilities, such as RES and emissions compliance, as well as development, implementation, and oversight of wholesale and renewable to retail market tariffs, and (2) existing regulatory mechanisms, such as the FAM. NS Power would welcome the opportunity to continue such discussions with the Board and regulatory stakeholders to help the Board determine whether more detailed consideration would be appropriate.

[NS Power Closing Submissions, p. 54]

4.5.1 Findings

[726] While the Board appreciates the complexity and challenges, a transition to performance-based rates should be explored. Key goals in such a transition would be the development of more predictable rate setting processes, the reduction of regulatory burden and the better alignment of utility incentives and customer interests. The Board will further consider how this may be moved forward.

4.6 Implementation of New Rates (Cyber Incident Impact)

[727] At the hearing, NS Power said that it now has communication with roughly 400,000 of its customer meters and has targeted the end of March to have all meters (approximately 555,000) communicating. It noted, however, that it was going to take time to get data from new meter reads and input that data into bills.

[728] NS Power explained that when a rate increase is implemented, it prorates the application of the new rates based upon the amount of time in the billing period that they were in effect. It also agreed that there was a potential that a longer period of time between actual meter readings might exist because of the cyber attack and that higher usage in a colder period could be charged at a higher than approved rate for that period of time given the impact of prorating rate changes:

THE CHAIR: Isn't the potential now, though, right now, that there is customers who have gone on for a longer period of time between actual reads than would have been the case with prior rate increases?

MR. WILLIAMS: There is — I do believe there is that potential, but I think it's certainly much more reduced than it would have been two or three months ago for sure.

THE CHAIR: Okay. But still some customers who have larger than you would want periods where you're in between actual reads, you might be proportionately estimating for purposes of rate changes across potential seasons in terms of use?

MR. WILLIAMS: I don't know that would be estimating across potential seasons at this point, but I think there is the potential there that it's longer than it would have been in some instances. But I would note that, I mean, prior to AMI technology we would have been in a very similar situation. We would have meter readers out there more regularly, and more meter readers on staff. But the issue is not a new one, in terms of having to estimate — the potential to have to estimate a bill despite the fact that there's been a rate increase.

THE CHAIR: Well, it's colder now. So if a customer is using more electricity now, and we don't get a decision now and effective rates don't come in [‘till] March, April, whenever, part of the period is going to be an early colder period where it should be a lower rate, and part would be a higher rate but would be warmer when they're, perhaps, using less electricity. But your response is to prorate that across all of them, which would in effect have the customer really paying a little bit higher than they would otherwise. Correct?

MR. WILLIAMS: Yes, sir, I agree. I mean, that is a reality in -- anytime there has been an increase in the past. And I'm going to keep going back, I suppose, to the fact that we've got 400,000 communicating at this point in time, and we do believe we're on track for March.

[Transcript, January 9, 2026, pp. 788-790]

[729] NS Power also stated that when it is able to read data from the meters, it can recover stored data about historical use in the range of 60 to 90 days. However, the data is only stored for that finite period and does not include some information, such as interval usage (e.g., 15-minute interval usage).

4.6.1 Findings

[730] The Board is concerned that customers who have higher usage during the recent colder period of the year might end up paying more than the approved current rate for the electricity they are currently using because of the impact of prorating. This concern is exacerbated in cases where the period of time between actual meter reads has been prolonged because of the cyber attack.

[731] The Board understands that before the implementation of AMI meters, the implementation of a new rate in the middle of a billing cycle might mean that the bill for that period would need to be prorated. However, it is not clear to the Board why any bill rate change needs to be prorated if an AMI meter is used. As the Board understands it, an AMI meter would be able to precisely determine the amount of energy used before a new rate came into effect and after the new rate came into effect. In such circumstances, the Board would expect the approved rates at the time the energy is consumed would be used.

[732] Unless NS Power is able to provide a compelling reason in its compliance filing demonstrating that it is not possible to use AMI data to avoid prorating bills to accommodate its proposed rate increase, the Board directs that the bills covering the time

that the new rates come into effect be prepared on the basis that the energy consumed in the billing period is charged at the actual rate that was in effect when the energy was actually used.

5.0 SUMMARY OF MAJOR FINDINGS AND DIRECTIVES

[733] The Board approves most components of the settlement agreement, subject to its findings below that amend the application. The following are approved:

- Maintaining NS Power's current return on equity of 9.0%, with an earnings band of 8.75% to 9.25%. The equity thickness for rate setting purposes remains at 40.0%;
- The establishment of the securitization deferral to defer depreciation expenses and financing costs related to the coal plants and thermal-related assets within the scope of the Decarbonization Deferral Account, but only effective from the date the rate increases in this application are implemented;
- NS Power's proposed depreciation rates. The depreciation study is approved, including the exclusion of decommissioning costs for the Wreck Cove, Mersey and Tusket hydro plants; the inclusion of partial decommissioning costs for NS Power's other hydro plants; the net salvage rates for plant accounts both within and outside the settlement agreement; and the asset service lives presented in the application;
- The proposed cost-of-service methodology and cost allocation among the various customer classes, except that NS Power is directed to implement a load carrying capability adjustment to account for the demand component served by the minimum system used to classify distribution system costs and to address other cost-of-service issues as noted in this decision;
- The PHP Deferral account, based on the assumptions in the settlement agreement, to track any variances in revenue between that which would occur based on the assumptions in the cost-of-service study treating PHP as an Above-the-Line customer versus that which results from the eventual Board-approved tariff for PHP. NS Power estimated \$18.2 million would accrue in the deferral if PHP remains as a Below-the-Line customer for the entirety of 2026 (Undertaking U-2), and there would also be a \$5.7 million fuel balance captured under the FAM;
- The EIFEL deferral, allowing NS Power to defer incremental tax expense of about \$7 million if an exemption is not enacted by the Government of Canada as it has announced;

- The inclusion of four Maritime Link transmission capital projects in rate base. The amount to be included in rate base is the net book value of these assets as of the date of the Board's Order;
- Continuing the Storm Cost Recovery Rider pilot in 2026 and 2027, but on a symmetrical basis, which allows for underspent Level 3 and 4 costs to be returned to customers;
- The change to the tariff language for the Demand Side Management Cost Recovery Rider;
- Revising the Open Access Transmission Tariff (OATT) rates to reflect changes in the generation and transmission asset mix and costs, changes in system usage since the last update in the 2023-2024 GRA, Board directives from the 2023-2024 GRA, and the revised methodology from the 2024 Cost of Service proceeding; and
- Other miscellaneous fee changes under the Schedule of Charges, such as for connection, reconnection, returned cheques, installation of recording equipment, contribution for three-phase service, load research charges, and pole attachment fees.

[734] However, the Board has made findings amending the general rate application and parts of the settlement agreement. It has made several adjustments in this decision to reduce NS Power's proposed revenue requirement or adjust the allocation of costs among customer classes, including:

- A further reduction of \$8 million in Operating, Maintenance and General expenses in each of 2026 and 2027 (over and above the \$9 million outlined in the settlement agreement);
- A reduction in NS Power's proposed executive compensation in both 2026 and 2027 to be consistent with the *Nova Scotia Power Incorporated Regulations*;
- The denial of NS Power's proposed deferral of general rate application OM&G costs (GRA deferral) for collection over the 2026-2027 period;
- A reduction of \$1.8 million in fuel and purchased power costs in 2026 to reflect the present estimate for Maritime Link assessment costs, and to update the current 2027 estimate;
- A peak load carrying capability adjustment of 0.4 kW per customer applied as a credit to the non-coincidental peak demand for determining the minimum system demand allocators for the distribution system costs (this change transfers the related costs from domestic, small general and unmetered customers to other rate classes) (Undertaking U-6); and

- The denial of the proposed AMI opt-out fee.

[735] The Board has issued the following directives to NS Power:

- To provide a reconciliation showing the annual collection of interim and final net salvage in rates from 2009 onwards in its next depreciation study. This information is to be presented for actual interim salvage costs that have been incurred each year for each of the hydro assets where NS Power has proposed to cease collection of the final net salvage costs for the assets (para. [166]);
- To undertake a consultation process with interested parties about the decommissioning of hydro plants and to report on the results of the consultation every six months, starting no later than October 1, 2026 (para. [189]);
- To file an updated depreciation study with its next general rate application, with several directives to address a comparison of the ALG and ELG methodologies, including, but not limited to:
 - The interaction between depreciation expense and return on rate base;
 - The extent to which actual true aged data has been used;
 - A NS Power specific ALG vs. ELG cross-over point analysis;
 - Comparison to other peer utility data, particularly related to actual age data, the retirement patterns experienced by those utilities, recommended asset service lives, and a description of what forces of retirement those utilities have that are consistent with those of NS Power;
 - Identification of specific factors in Nova Scotia that differ from other peer utilities that would lead to a higher rate of retirement or greater forces of retirement;
 - The book accumulated depreciation reserve balance and calculated accumulated reserve balance under both the ALG and ELG procedure;
 - An evaluation of whether a change to the ALG procedure would violate the principles of gradualism and moderation, and whether a “phasing-in” of ALG would be appropriate; and
 - The proposed depreciation by asset account under both ELG and ALG procedures (paras. [233-234]);
- In its next depreciation study, to address Mr. Madsen’s recommendations related to asset service life accounts 354, 356, 367, and 390.10 (para. [254]);

- In its next depreciation study, provide at minimum the following information in support of both production Plant and mass property:
 - Detailed management notes for each account;
 - All analysis and studies performed by management for each asset to confirm the expected life;
 - All updated IRP documents;
 - A reconciliation of the lives proposed in the depreciation study to the lives proposed in the IRP; and
 - The peer analysis relied upon by the company in an Excel file (para. [255]);
- To address the additional cost-of-service concerns raised by Synapse in its application to the Board later in 2026, as required in the settlement agreement, in addition to the review of the minimum system v. basic customer method for allocating distribution system costs (para. [616]), as well as the analysis necessary to calculate the load carrying capability of its minimum system (para. [627]);
- To address the issues raised by Renewall in its closing submissions, if the utility brings forward any application relating to the OATT tariff or charges before responsibility for the transmission tariff is transferred to the Nova Scotia Independent Energy System Operator, including if NS Power files a general rate application (para. [642]);
- To address the setting of customer charges in its next general rate application (para. [653]);
- To file a revised Climate Change Adaptation Plan by October 1, 2026, outlining climate related impacts on the utility's resources, activities and assets; actions to address the issues identified; potential and likely adaptation measures; and any challenges to mitigating risks (para. [711]); and
- Unless NS Power is able to provide a compelling reason in its compliance filing demonstrating that it is not possible to use AMI data to avoid prorating bills to accommodate its proposed rate increase, the Board directs that the bills covering the time that the new rates come into effect be prepared on the basis that the energy consumed in the billing period is charged at the actual rate that was in effect when the energy was actually used (para. [732]).

6.0 COMPLIANCE FILING

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

- A further reduction of \$8 million in Operating, Maintenance and General expenses in each of 2026 and 2027 (over and above the \$9 million outlined in the settlement agreement);
- A reduction in NS Power's proposed executive compensation in both 2026 and 2027 to be consistent with the *Nova Scotia Power Incorporated Regulations*;
- The denial of NS Power's proposed deferral of general rate application OM&G costs (GRA deferral) for collection over the 2026-2027 period;
- A reduction of \$1.8 million in fuel and purchased power costs in 2026 to reflect the present estimate for Maritime Link assessment costs, and to update the current 2027 estimate;
- To make the change to s. 3.2.8 of the FAM POA discussed in NSEB IR-33 and the other proposed amendments to the FAM POA and to the FAM Tariff;
- A peak load carrying capability adjustment of 0.4 kW per customer applied as a credit to the non-coincidental peak demand for determining the minimum system demand allocators for the distribution system costs (this change transfers the related costs from domestic, small general and unmetered customers to other rate classes) (Undertaking U-6); and
- The denial of the proposed AMI opt-out fee.

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

[738] The Board approves NS Power's application, subject to the Board's findings and directives in this decision. The Board approves the rates and charges for 2026 effective the date of the Board's Order approving final rates in this matter and the rates and charges for 2027 effective January 1, 2027.

[739] Although the NSUARB approved rate increases in NS Power's last general rate application effective the date of its decision, this is not the normal practice. The normal practice, assuming an intention to implement rates on January 1st, is for NS Power to file its application early enough to allow for an appropriate process to occur and a decision to be made before January 1st. As noted earlier, NS Power did not file its application until late September 2025, practically ensuring that the matter would not be concluded before year-end.


[740] Failing that, the normal process is for rates to come into effect on the date of the Board's final Order in the matter. The exercise of the Board's discretion to do otherwise in NS Power's last general rate application was done in the unique circumstances arising at that time and it did not reflect the longstanding requirement for a compliance filing to determine the rates before they came into effect. Moreover, because new rates cannot be implemented until a final Order, if rates come into effect on the date of the Board's decision, then any bills issued after the Board's decision but before a final Order following a compliance filing would necessarily need to be retroactively adjusted. It is potentially confusing and frustrating for customers to see these sorts of adjustments on future bills. At the present time, this would only be aggravated because of recent and ongoing customer concerns about NS Power's estimation and billing practices in the wake of the cyber incident. In any event, the Board finds that allowing rates to come into effect on the date of a decision rather than when finalized in an Order should not become a customary practice.

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

DATED at Halifax, Nova Scotia, this 25th day of March 2026.


Stephen T. McGrath


Roland A. Deveau


Steven M. Murphy