DECISION **2023 NSUARB 12**
M10431

NOVA SCOTIA UTILITY AND REVIEW 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, LL.B., Chair
Roland A. Deveau, K.C., Vice Chair
Steven M. Murphy, MBA, P.Eng., Member

APPLICANT: **NOVA SCOTIA POWER INC.**
Colin J. Clarke, K.C.
Blake Williams, Counsel

INTERVENORS: **SEE APPENDIX A**

CONSUMER ADVOCATE
William J. Mahody, K.C.
Christine Murray, Counsel

SMALL BUSINESS ADVOCATE
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XPLORE INC. (formerly Xplornet Communications Inc.)
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BOARD COUNSEL: S. Bruce Outhouse, K.C.

HEARING DATES: September 12-23, 2022

UNDERTAKINGS: October 14, 2022

FINAL SUBMISSIONS: December 21, 2022

DECISION DATE: **February 2, 2023**

DECISION: **The Board approves most of the GRA Settlement Agreement providing for average rate increases of 6.9% across all customer classes in each of 2023 and 2024. The Board approves the rates and charges for 2023 effective the date of this decision and the rates and charges for 2024 effective January 1, 2024. The Board also approves the Storm Rider, the DSM Rider and the Decarbonization Deferral Account in principle, each as described in the GRA Settlement Agreement. The Board does not approve three items in the agreement, namely the proposed AMI Opt-out fee, the creation of a regulatory asset for Annapolis Tidal Generating Facility, and the four Maritime Link transmission capital projects.**

The Board endorses an agreement between the Affordable Energy Coalition, the Consumer Advocate, and NS Power to consider possible changes to the bill payment, credit and collection rules for low-income customers.

The Board directs NS Power to conduct a depreciation study and to start a consultative process to develop a Climate Change Adaptation Plan.

The Board denies a request by the Municipal Electric Utilities for a BUTU Tariff GHG credit, but accepts a recommended change in determining a charge for Capacity Based Ancillary Services and directs a review of other charges.

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1.0 SUMMARY

[1] NS Power applied to the Nova Scotia Utility and Review Board for smoothed power rate increases of 3.3% per year for residential customers effective August 1, 2022, January 1, 2023, and January 1, 2024. Proposed rate increases for other customer classes varied from this amount, with the proposed overall average smoothed rate increases amounting to 3.6%.

[2] This was NS Power's first general rate application (GRA) for an increase to its non-fuel rates since the Board's decision setting 2013-2014 rates.

[3] NS Power's original forecast for fuel and purchased power costs for the application was generated in May 2021. NS Power filed a Fuel Update on September 2, 2022. It showed a significantly higher forecast for fuel and purchased power costs, representing an increase of $681.5 million over the original forecast for the period from 2022 to the end of 2024. The Province of Nova Scotia agreed to provide some relief to NS Power customers from this amount by exempting NS Power from approximately $165 million of greenhouse gas (GHG) compliance expenses to the end of 2022.

[4] The Board held the public hearing from September 12 to 23, 2022. The evidentiary record contained over 30,000 pages of information filed by NS Power and the parties, including representatives for the major customer classes representing most of the Utility's customers.

[5] On October 19, 2022, the Nova Scotia Government introduced Bill 212 in the Legislature, after the hearing had finished, but before written Closing Submissions by the parties. The legislation came into effect on November 8, 2022. It amended the *Public Utilities Act*, adding new provisions that specifically impacted the current GRA, including, among other items, a requirement that the net rate increase for the Utility, across all rate

classes, in 2022, 2023 and 2024 must not be greater than 1.8%, with the exception of an increase for fuel costs and demand side management costs. Further, the legislation required revenue generated from the net rate increase may only be used to improve service reliability.

[6] On November 24, 2022, NS Power filed a GRA Settlement Agreement with the Board, resolving many of the issues in the GRA. The GRA Settlement Agreement was signed by representatives for all major customer classes, representing most of NS Power's customers. In addition to agreeing on many issues canvassed in the GRA, the parties agreed that, with the Board's approval, the average rate increase across all customer classes should be 6.9% (including fuel and non-fuel costs) in each of 2023 and 2024. The parties also agreed to defer part of the expected increase in fuel costs to later years.

[7] The 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.

[8] Further, consistent with principles of utility rate regulation recognized by the Supreme Court of Canada, the Board cannot simply disallow NS Power's reasonable costs to make rates more affordable. These principles ensure fair rates and the financial health of a utility so it can continue to invest in the system providing services to its customers. While the Board can (and has) disallowed costs found to be imprudent or unreasonable, absent such a finding, NS Power's costs must be reflected in the rates

paid by customers. Regulatory tools, such as deferrals, are available to the Board to mitigate the impact of rate increases, but there are trade-offs involved with using these tools as they often result in higher costs in the longer term.

[9] Having reviewed all the evidence, submissions and the law, the Board is satisfied that the GRA Settlement Agreement, considered as a whole, is in the public interest and that it should be approved, with certain exceptions. The Board is satisfied that the negotiated average 6.9% rate increases in each of 2023 and 2024 are reasonable and appropriate, and that the increases comply with recent amendments to the *Public Utilities Act* introduced through Bill 212. The Board approves the rates and charges for 2023 effective the date of this decision and the rates and charges for 2024 effective January 1, 2024.

[10] In considering issues like the rate of return and the financing costs for fuel and other deferrals, the Board finds that NS Power's recent credit downgrades are a relevant factor because they heighten concerns around NS Power's credit metrics and the risk of further downgrades, resulting in the potential imposition of even more costs on ratepayers.

[11] In the GRA Settlement Agreement, a balance was struck between NS Power and representatives of most of its customer classes (including the Consumer Advocate on behalf of all residential customers and the Affordable Energy Coalition, which works on behalf of low- and modest-income Nova Scotians across the province). Given the broad acceptance by customer representatives and other parties, and the looming cost pressures likely to arise from higher forecasted fuel costs and the transition to a net-zero carbon economy, the Board finds the proposed rate increases in the GRA

Settlement Agreement to be just. It is not appropriate in this case to defer even more fuel costs for additional and temporary rate relief in the test years. This would run the very real risk of compounding rate pressures in the future and reducing the flexibility that may be available to manage those costs in a reasonable timeframe.

[12] The Board also finds that other components of the GRA Settlement Agreement appropriately resolve issues raised in the application. As a result, 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 increases from 37.5% to 40.0%;

- Agreeing in principle to the establishment of a Decarbonization Deferral Account to address the retirement of coal plants and related decommissioning costs, subject to a further consultative process;

- Implementing a Storm Cost Recovery Rider for a three-year trial period, and a DSM Cost Recovery Rider;

- Conducting an updated Cost of Service Study and Line Loss Study before the next GRA or by December 31, 2025, whichever is sooner, subject to stakeholder engagement;

- Applying a 25% reduction to the proposed increase to the 2023 customer charges;

- Increasing the credit amount in the Large Industrial Interruptible Rider;

- Adopting the negotiated amount for the pole attachment fee as per the agreement between NS Power and the telecommunications carriers; and

- Capping the Open Access Transmission Tariff at a maximum increase of 1.8% in 2023 and 0% in 2024.

[13] The Board does not approve three items in the GRA Settlement Agreement. It does not approve NS Power's proposed AMI opt-out fee. It does not approve the regulatory amortization of the Annapolis Tidal Generation Facility, which is to remain in rate base. Further, the Board defers approval of the four Maritime Link transmission

capital projects originally totalling about $45 million until benefits to ratepayers have been demonstrated, as discussed later in this decision.

[14] Moreover, the Board directs NS Power to prepare a depreciation study before the next GRA. The Board also endorses an agreement between the Affordable Energy Coalition, the Consumer Advocate and NS Power to review the outcomes of 2013 changes to the Utility's bill payment, credit and collection rules for low-income customers and to consider additional changes. In addition, the Board directs NS Power to engage in a consultative process to develop a Climate Change Adaptation Plan.

[15] The Board denies the Municipal Electric Utilities' request for a Wholesale Market Backup/Top-up (BUTU) Tariff GHG credit. However, the Board accepts one of their recommendations for Capacity Based Ancillary Services, and directs a review of their other recommendations.

[16] Nova Scotia is on the brink of unprecedented change in the energy sector. The Company and its customers must contend with this change at an accelerating pace. Government, regulators, and utilities will need to work collaboratively to mitigate the risks of this rapid change, and to ensure they meet the aggressive decarbonization goals set by federal and provincial governments. In terms of the comprehensive GRA Settlement Agreement that was signed, and the agreement to pursue consultative processes on the Decarbonization Deferral Account and an updated Cost of Service Study, the Board considers it a positive development that there is a constructive dialogue occurring between the Utility and its customers about the energy transition.

2.0 BACKGROUND

[17] This decision is about an application filed on January 27, 2022, by Nova Scotia Power Incorporated (NS Power, Company, Utility), for approval of revisions to its Rates, Charges and Regulations (application or GRA). This was NS Power's first general rate application for an increase to its non-fuel rates since the Board's decision setting 2013-2014 rates. Since that proceeding, inflation has increased over 20% from 2014 to 2022.

[18] NS Power filed an updated application on February 18, 2022, to address an issue with income tax and interest related to the Fuel Adjustment Mechanism (FAM) balance. The updated filing also reflected NS Power's withdrawal of their request for a system access charge for customer solar panels.

[19] The application requested the Board's approval of a Rate Stability Plan (RSP). The proposed RSP was a three-year rate plan, with smoothed overall rate increases for each of the customer classes as outlined in this excerpt from Figure 12-5:

	August 1, 2022	January 1, 2023	January 1, 2024
Domestic Service Tariff			
Total	**3.3%**	**3.3%**	**3.2%**
Small General Tariff			
Total	**3.6%**	**3.7%**	**3.7%**
General Tariff			
Total	**4.0%**	**4.0%**	**4.0%**
Large General Tariff			
Total	**5.2%**	**5.2%**	**5.2%**
Small Industrial Tariff			
Total	**5.1%**	**5.2%**	**5.3%**
Medium Industrial Tariff			
Total	**5.6%**	**5.6%**	**5.7%**
Large Industrial Tariff			
Total	**3.3%**	**3.4%**	**3.5%**
Other Classes			
Total	**0.0%**	**0.2%**	**0.3%**
Total FAM Classes			
Total	**3.6%**	**3.6%**	**3.6%**

[Exhibit N-16, Figure 12-5, pp. 107-108]

[20] NS Power's application also included:

- A request to maintain its return on common equity of 9.0%, but to increase the approved range of earnings from 8.50% to 9.50% (currently 8.75% to 9.25%), and to phase-in an increase to the common equity component from 37.5% towards 45%;
- A proposal for a 50/50 Earnings Sharing Mechanism for overearnings, with the ratepayers' share applied to the Decarbonization Deferral Account (DDA);
- A Storm Rider to recover costs related to Level 3 and 4 storms;
- A Decarbonization Deferral Account;
- A Demand Side Management Rider (DSM Rider or DCRR);
- Changes to the Miscellaneous Charges in NS Power's Regulations, including:
  i. The establishment of an Advanced Metering Infrastructure (AMI) Opt-out Fee, including revisions to Regulation 5.1 (Meter Reading);
  ii. Changes to the fees and charges in Regulations 7.1, 7.2 and 7.3 as more fully described in the application; and
  iii. Increase to the Pole Attachment Fee from $14.15 to $37.71;
- Changes to the Domestic Service and Small General Customer Charges;
- An increase to the Large Industrial Interruptible Credit;
- Changes to rates in the Open Access Transmission Tariff (OATT); and
- Approval of four Capital Work Orders originally totalling $44.7 million for Maritime Link related transmission work.

[21] The proposed rate increases included increased fuel costs. Any Fuel Adjustment Mechanism Actual Adjustments (AA) or Balancing Adjustments (BA) calculated during the Rate Stability Period would be deferred to 2025.

[22] NS Power asked to delay its Fuel Update and the start of the hearing to facilitate discussions with the Province of Nova Scotia about the significant escalation in fuel and purchased power costs since NS Power's forecast for the general rate application. NS Power and the Province were discussing whether measures could be taken to lessen the impact on customers. NS Power's request was supported by the Province, through the Department of Natural Resources and Renewables (NRR). The Board granted these requests.

[23] NS Power's original forecast for fuel and purchased power costs for the general rate application was generated in May 2021. NS Power filed a Fuel Update on

September 2, 2022, which showed that total forecast fuel and purchased power costs for the test period were projected to increase by $681.5 million more than initially forecast in its application (approximately one-third of its original forecast fuel budget). The Fuel Update had a potentially significant impact on NS Power's proposed power rates for its customers. However, the Province of Nova Scotia agreed to provide relief to NS Power customers for the GHG compliance expenses to the end of 2022, which the Company previously forecast as part of its fuel costs. This GHG relief is forecast to remove GHG compliance costs to the end of 2022 of about $165 million from NS Power's Fuel Update forecast. Assuming NS Power is subject to the Federal Backstop Program for GHG compliance, which is scheduled to begin on July 1, 2023, the Company estimates the additional cost for emissions compliance in 2023 and 2024 will be $116 million and $127 million, respectively. These latter two amounts for the cost of emissions compliance were not included in the updated fuel forecast provided by NS Power.

[24] The public hearing was duly advertised in accordance with sections 64 and 86 of the *Public Utilities Act*, R.S.N.S. 1989, c. 380 (*Act* or *PUA*).

[25] A number of formal Intervenors responded to NS Power's application and participated in the hearing. The Consumer Advocate (CA); Small Business Advocate (SBA); the Industrial Group (IG); Dalhousie University; the Affordable Energy Coalition; the Ecology Action Centre; Municipal Electrical Utilities of Nova Scotia (MEUs); Port Hawkesbury Paper LP (PHP); Nova Scotia Department of Natural Resources and Renewables (NRR); EfficiencyOne (EOne); Bragg Communications Incorporated, operating as Eastlink (Eastlink); the Nova Scotia Liberal Caucus Office; the Nova Scotia NDP Caucus Office; and Freeman Lumber, participated in the hearing. Albert Dominie,

the consultant for the Municipal Electric Utilities, passed on the eve of the hearing. In his current role, and in his former capacity as NS Power's Manager of Rates and Regulations, Mr. Dominie contributed in a significant way to electricity proceedings before the Board. His knowledge and insight will be missed.

[26] The Notice of Public Hearing advised the public that they could file submissions with the Board outlining their views regarding NS Power's application. The Board received nearly 1,000 letters of comment from the public and two individuals made presentations at the evening session on September 12, 2022.

[27] Many of the written comments noted the impact the rate increases would have on customers, especially on low- and fixed-income customers. A number of other concerns were noted, including: the proposed system access charge on solar panel installations; executive compensation and bonus levels; rate of return and company earnings; the reliability of the electricity system; the need for renewable energy; and the phasing-out of coal plants.

[28] These concerns were echoed during the evening session, along with additional concerns about the cost of living and the need to avoid the proposed rate increases. During this session, it was also suggested that there is no financial incentive for NS Power to abandon its large capital-intensive coal-fired infrastructure and transition to renewable sources of energy, including distributed energy resources, adding that such renewable sources are generally more affordable. Further, one speaker noted that NS Power earns return on any deferred fuel costs, and that alternative financing should be pursued from governments and banks for such deferrals. For similar reasons, the same speaker suggested that the DDA should be rejected.

[29] The Board considered all the comments made in the written submissions and during the evening session in making its decision. The Board is mindful of its responsibility to consider the public interest in its decisions.

[30] On November 24, 2022, following the hearing, but before written submissions were completed, NS Power filed a Settlement Agreement between itself and Intervenors representing most of NS Power's customers which resolved many of the issues in this proceeding. The parties agreed that the average rate increase across all customer classes would be 6.9% (including fuel and non-fuel costs) in each of 2023 and 2024. Also, during the hearing, NS Power filed a Settlement Agreement with the telecommunications carriers who had intervened in the proceeding about the proposed increase to the Pole Attachment Fee.

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

[31] The Board is an administrative body, established under the laws of the Province of Nova Scotia as a continuation of predecessor boards under the *Utility and Review Board Act*, S.N.S. 1992, c. 11 (*UARB Act*). It exercises adjudicative and regulatory decision-making authority under approximately 40 statutes and related regulations. In doing so, 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.

[32] The Board is what has sometimes been referred to as a "creature of statute." In *Administrative Law in Canada*, 7th ed. (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.
>
> [p. 137]

[33] The Board summarized the application of these principles to itself 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.

[34] The Board's general functions, power, duties and jurisdiction are expressly addressed in the *UARB Act*:

> **Functions, powers and duties**
>
> 4 (1) The Board has those functions, powers and duties that are, from time to time, conferred or imposed on it by

> (a) this Act, the *Assessment Act*, the *Expropriation Act*, the *Gasoline and Diesel Oil Tax Act*, the *Health Services Tax Act*, the *Heritage Property Act*, the *Insurance Act*, the *Motor Carrier Act*, the *Municipal Government Act*, the *Public Utilities Act*, the *Education Act*, the *Shopping Centre Development Act*, the *Tobacco Tax Act* or any enactment; and
>
> (b) the Governor in Council.
>
> (2) The Governor in Council may assign to the 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 Sections 49 and 50 apply *mutatis mutandis* with respect to that board, commission or agency.
>
> **Jurisdiction**
>
> 22 (1) The Board has exclusive jurisdiction in all cases and in respect of all matters in which jurisdiction is conferred on it.
>
> (2) The Board, as to all matters within its jurisdiction pursuant to this Act, may hear and determine all questions of law and of fact.

[35] The *PUA* gives the Board broad regulatory oversight over public utilities and the authority to discharge its regulatory responsibilities. The Board's principal responsibility in regulating utilities is to help ensure:

a) safe and adequate service;

b) just and reasonable rates; and

c) lowest long-term cost.

[36] 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. <u>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.</u>
>
> <u>[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.</u>
>
> [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 <u>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.</u> [Emphasis added]

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

[37] As noted already, the Board's powers are defined by legislation. Section 45 of the *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) <u>Every public utility shall be entitled to earn annually such return</u> 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.

45(2) <u>Such return shall be in addition to such expenses</u> 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]

[38] 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, by necessary implication, to the purposes of the statute.

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

> 17 <u>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.</u>
>
> 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.
>
> 19 This general requirement is supplemented by provisions such as s. 25 respecting pole line standards, s. 52 prohibiting electric voltage and frequency variations of more than 4% and ss. 49-51 respecting abandonment or duplication of service, and by rules and regulations made by the Board for each utility's operation. Compliance with this requirement is accomplished by the Board's continuing supervision of a utility (s. 19), by requiring a utility to submit to the Board detailed reports and accounts, "to show completely and in detail the entire operation of the public utility in furnishing its product or service to the public" (s. 33; also ss. 26, 45-47). The Board may investigate the adequacy of service on its own motion (s. 18) or on complaint (s. 78(1)), and by its staff may inspect books of a utility (s. 75) and make tests or examinations to determine the safety and adequacy of service (s. 77).
>
> 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 <u>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.</u>

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]

[40] 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 it 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]

[41] The Board continues to make its decisions in accordance with the *PUA* and the principles noted above.

4.0 AMENDMENTS TO THE *PUBLIC UTILITIES ACT* (OCTOBER 2022)

[42] This GRA proceeding was significantly impacted by Bill 212, which the Nova Scotia Government introduced in the Legislature on October 19, 2022, after the hearing had finished, but before written Closing Submissions by the parties. The legislation contained various amendments to the *PUA*, including several new provisions that specifically referenced the current Matter M10431. The amended Bill passed Third Reading on November 8, 2022, and received Royal Assent on November 9, 2022 (S.N.S. 2022, c. 52) (*PUA* amendments or Bill 212). The provisions directly impacting this matter are as follows:

> **64A(3)** For the purpose of Board Case Number M10431, the net rate increase for the utility, across all rate classes, in 2022, 2023 and 2024 must not be greater than one and eight-tenths per cent, with the exception of an increase respecting
>
> (a) fuel and purchased power; and
>
> (b) demand-side management approved by the Board.
>
> **(3A)** Revenue generated from the net rate increase referred to in subsection (3), with the exception of increases respecting a matter referred to in clause (3)(a) or (b),
>
> (a) must be kept separate from other funds of the utility; and
>
> (b) may only be used to improve the reliability of service to ratepayers.
>
> **64AA** For the purpose of Board Case Number M10431,
>
> (a) Nova Scotia Power Incorporated's return on equity must be set at a rate not greater than nine and one-quarter per cent;
>
> (b) Nova Scotia Power Incorporated's equity ratio must not be greater than forty per cent.
>
> **64AB (1)** The Board may approve the payment of interest to Nova Scotia Power Incorporated on an outstanding balance for the Fuel Adjustment Mechanism, or any other regulatory deferral.
>
> **(2)** To be eligible for a payment of interest under subsection (1),
>
> (a) Nova Scotia Power Incorporated must demonstrate a balance is outstanding, or there is a clear demonstrated prediction for an outstanding balance, for a period of not less than twelve months prior to a request for the payment of interest; and

(b) the minimum amount on an outstanding balance must be greater than one million dollars.

(3) Interest must be calculated

(a) from the date the balance is outstanding using simple interest at the Bank of Canada policy interest rate plus one and three-quarters per cent, unless otherwise directed by the Board; and

(b) on a per year basis.

(4) Any request for the payment of interest on an outstanding balance must include the interest calculations for the Board for review.

64C Where Nova Scotia Power Incorporated's regulated return on equity exceeds the range approved by the Board in a calendar year, any amount that exceeds that range must be returned to ratepayers in a manner approved by the Board.

[43] The former version of s. 64A(3) was repealed. While NS Power is unable to be granted a general rate increase within two years of the prior increase (s. 64A(2)), the former s. 64A(3) allowed the Utility to seek a general rate increase sooner, provided the Board found that "exceptional circumstances exist that have caused or will cause substantial financial harm to the ratepayers of the utility or to the utility". The repeal of the provision removed that exemption.

[44] Further, while not directly impacting the current GRA, the amendments also added the following provision, which will impact NS Power over the longer term leading to the next general rate application:

30(5) The Board shall, with the assistance of such engineers, accountants, valuators, 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.

[45] To allow NS Power and the Intervenors to consider the ramifications of the new statutory amendments, the initial Closing Submissions were delayed from the previously scheduled date of November 4, 2022, to November 23, 2022, with Reply Submissions delayed from the prior date of November 18, 2022, to December 21, 2022.

[46] An immediate impact of Bill 212 was that credit rating agencies revised their outlooks for NS Power and Emera. S&P Global and DBRS Morningstar lowered NS Power's credit rating on November 21, 2022, and December 20, 2022, respectively, directly impacting NS Power's financing abilities in the debt markets, putting pressure on its cash flow-to-debt metrics, and potentially discouraging equity investment.

5.0 STATUTORY INTERPRETATION PRINCIPLES

[47] 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.

[48] *Verdun v. Toronto Dominion Bank,* [1996] 3 S.C.R. 550, and cases following it (see, for example, *Chartier v. Chartier,* [1998] S.C.J. No. 79; *Re Rizzo & Rizzo Shoes Ltd.*, [1998] 1 S.C.R. 27), make it clear that the Supreme Court of Canada has adopted what it calls the "modern contextual approach" to legislative interpretation, supplanting earlier rules it has supported, such as the "equitable construction approach", the "plain meaning rule", and the "golden rule".

[49] In *Re Rizzo & Rizzo Shoes Ltd.*, Mr. Justice Iacobucci said at paragraph 21:

> ... Elmer Driedger in *Construction of Statutes* (2nd ed. 1983) best encapsulates the approach upon which I prefer to rely. He recognizes that statutory interpretation cannot be founded on the wording of the legislation alone. At p.87, he states:

> Today there is only one principle or approach, namely, the words of an Act are to be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament.

[50] On the matter of the purpose of legislation, *Nova Scotia (Crop and Livestock Insurance Commission) v. DeWitt,* [1996] N.S.J. No. 566 (S.C.), is of interest. Goodfellow, J., quotes Driedger (3rd ed.) at pages 38-39:

> ... Modern courts do not need an excuse to consider the purpose of legislation. Today purposive analysis is a regular part of interpretation, to be relied on in every case, not just those in which there is ambiguity or absurdity. As Matthews, J.A. recently wrote in *R. v. Moore* [(1985), 67 N.S.R. (2d) 241, at 244 (C.A.)]:
>
> > From a study of the relevant case law up to date, the words of an Act are always to be read in light of the object of that Act. Consideration must be given to both the spirit and the letter of the legislation.
>
> ... *Thomson v. Canada* (Minister of Agriculture) (1992), 1 S.C.R. 385 at 416, L'Heureux-Dubé, J., wrote:
>
> > [A] judge's fundamental consideration in statutory interpretation is the purpose of legislation.

[51] The Nova Scotia Court of Appeal reiterated the modern principle of statutory interpretation in *Sparks v. Holland*, 2019 NSCA 3. Farrar, J.A., stated:

> [27] The Supreme Court of Canada and this Court have affirmed the modern principle of statutory interpretation in many cases that "[t]he words of an Act are to be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament (*Rizzo & Rizzo Shoes Ltd. (Re)*, [1998] 1 S.C.R. 27 at ¶21).
>
> [28] This Court typically asks three questions when applying the modern principle. These questions derive from Professor Ruth Sullivan's text, *Sullivan on the Construction of Statutes*, 6th ed (Markham, On: LexisNexis Canada, 2014) at pp. 9-10.
>
> [29] Ms. Sullivan's questions have been applied in several cases, including *Keizer v. Slauenwhite*, 2012 NSCA 20, and more recently, in *Tibbetts*. In summary, the Sullivan questions are:
>
> 1. What is the meaning of the legislative text?
>
> 2. What did the Legislature intend?
>
> 3. What are the consequences of adopting a proposed interpretation?
>
> [Sullivan, pp. 9-10]

[52] 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, these principles also apply to administrative decision makers to require that legislation be interpreted consistent with its text, context and purpose. However, the form of analysis may look different than one undertaken by a court and may be enriched by the specialized expertise and experience of the decision maker:

> [117] A court interpreting a statutory provision does so by applying the "modern principle" of statutory interpretation, that is, that the words of a statute must be read "in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament": *Rizzo & Rizzo Shoes Ltd. (Re)*, [1998] 1 S.C.R. 27, at para. 21, and *Bell ExpressVu Limited Partnership v. Rex*, 2002 SCC 42, [2002] 2 S.C.R. 559, at para. 26, both quoting E. Driedger, *Construction of Statutes* (2nd ed. 1983), at p. 87. Parliament and the provincial legislatures have also provided guidance by way of statutory rules that explicitly govern the interpretation of statutes and regulations: see, e.g., *Interpretation Act*, R.S.C. 1985, c. I-21.
>
> [118] This Court has adopted the "modern principle" as the proper approach to statutory interpretation, because legislative intent can be understood only by reading the language chosen by the legislature in light of the purpose of the provision and the entire relevant context: Sullivan, at pp. 7-8. Those who draft and enact statutes expect that questions about their meaning will be resolved by an analysis that has regard to the text, context and purpose, regardless of whether the entity tasked with interpreting the law is a court or an administrative decision maker. An approach to reasonableness review that respects legislative intent must therefore assume that those who interpret the law — whether courts or administrative decision makers — will do so in a manner consistent with this principle of interpretation.
>
> [119] Administrative decision makers are not required to engage in a formalistic statutory interpretation exercise in every case. As discussed above, formal reasons for a decision will not always be necessary and may, where required, take different forms. And even where the interpretive exercise conducted by the administrative decision maker is set out in written reasons, it may look quite different from that of a court. The specialized expertise and experience of administrative decision makers may sometimes lead them to rely, in interpreting a provision, on considerations that a court would not have thought to employ but that actually enrich and elevate the interpretive exercise.
>
> [120] But whatever form the interpretive exercise takes, the merits of an administrative decision maker's interpretation of a statutory provision must be consistent with the text, context and purpose of the provision. In this sense, the usual principles of statutory interpretation apply equally when an administrative decision maker interprets a provision. Where, for example, the words used are "precise and unequivocal", their ordinary meaning will usually play a more significant role in the interpretive exercise: *Canada Trustco Mortgage Co. v. Canada*, 2005 SCC 54, [2005] 2 S.C.R. 601, at para. 10. Where the meaning of a statutory provision is disputed in administrative proceedings, the decision maker must demonstrate in its reasons that it was alive to these essential elements.

> [121] The administrative decision maker's task is to interpret the contested provision in a manner consistent with the text, context and purpose, applying its particular insight into the statutory scheme at issue. It cannot adopt an interpretation it knows to be inferior — albeit plausible — merely because the interpretation in question appears to be available and is expedient. The decision maker's responsibility is to discern meaning and legislative intent, not to "reverse-engineer" a desired outcome. [Emphasis added]

[53] The Board must also have regard to the *Interpretation Act*, R.S.N.S. 1989, c. 235, including ss. 9(1) and 9(5):

> **9(1)** The law shall be considered as always speaking and, whenever any matter or thing is expressed in the present tense, it shall be applied to the circumstances as they arise, so that effect may be given to each enactment, and every part thereof, according to its spirit, true intent, and meaning.
>
> **9(5)** Every enactment shall be deemed remedial and interpreted to insure the attainment of its objects by considering among other matters
> (a) the occasion and necessity for the enactment;
> (b) the circumstances existing at the time it was passed;
> (c) the mischief to be remedied;
> (d) the object to be attained;
> (e) the former law, including other enactments upon the same or similar subjects;
> (f) the consequences of a particular interpretation; and
> (g) the history of legislation on the subject.

6.0 SETTLEMENT AGREEMENT

6.1 Settlement Agreement by the Parties

[54] Two Settlement Agreements were filed with the Board during this proceeding. On September 16, 2022, NS Power filed a Settlement Agreement reached between the Utility and various telecommunications carriers proposing a revised pole attachment fee compared to that originally proposed in the GRA. This Settlement Agreement, and the issues about the pole attachment fee, are described in greater detail later in this decision.

[55] On November 24, 2022, NS Power filed a Settlement Agreement with the Board resolving many of the issues in the GRA between the Utility and Intervenors representing most of NS Power's customers (GRA Settlement Agreement). The GRA Settlement Agreement was signed by the CA, SBA, Industrial Group, the MEUs, the

Affordable Energy Coalition, the Ecology Action Centre and Dalhousie University. In addition to agreeing on many issues canvassed in the GRA, the parties agreed that, with the Board's approval, the average rate increase across all customer classes would be 6.9% (including fuel and non-fuel costs) in each of 2023 and 2024. The terms of the settlement were set out in a schedule to the agreement which provided as follows:

Terms of Settlement

It is acknowledged that, subject to Board approvals, rate increases other than those identified below may occur prior to the effective date of the next general rate application in relation to Board-approved AA/BA Riders or other deferred amounts.

GRA Element	Settlement Terms
Potential Deferral Relief	- The parties agree that these Terms of Settlement do not bar NS Power from applying to the Board to defer costs during the Test Years 2023 and 2024, consistent with the *Public Utilities Act* RSNS 1989, c. 380, as amended, and that all parties will be free to take any position they wish with regard to any such application. Any costs proposed to be deferred, and the allocation and amortization of such costs, would be subject to review and decision by the Board at that time.
Deferral / Regulatory Asset Financing Costs	- All financing costs for deferrals are to be calculated using rates equivalent to NS Power's approved Weighted Average Cost of Capital (WACC), as approved by the Board from time to time, or as otherwise directed by the Board.
Overall Rate	- The average rate increase across all customer classes will be 6.9% in each of 2023 and 2024 (see anticipated revenue increase table attached as Schedule "B") with the implementation of an AA/BA Rider in each of 2024 and 2025 to recover historical under-recovered fuel costs. - As the rate increase required to collect under-recovered fuel amounts in a 2024 AA/BA Rider is material for all or certain of the customer classes, the parties will work in a good faith manner to defer a portion of the impact of the increase and costs to 2025 or an additional period as may be reasonable and appropriate. NS Power will apply in October 2023 to set the AA/BA rider for 2024. For greater certainty, as the four Wholesale Market customers (the MEUs) were not FAM customers during the 2020-2022 period, none of the historical under-recovered fuel costs on account of 2020-2022 will be recoverable from those customers.

Non-fuel Rate	- The non-fuel components of the 6.9% average increase in each of 2023 and 2024 consist of the following: - 2023: average 5.4% (1.8% non-fuel and 3.6% DSM) - 2024: average 0.3% (DSM)
Fuel Rate	- The fuel component of the 6.9% average increase in each of 2023 and 2024 consists of the following: - 2023: average 1.5% - 2024: average 6.6% and an AA/BA Rider for historical under-recovery
Decarbonization Deferral Account (DDA)	- The parties agree in principle to a DDA to recover undepreciated thermal asset NBV and unrecovered decommissioning costs and further agree to engage constructively in a consultative process to confirm the practice and procedures that will be followed to establish the DDA and its scope, to effect the transfer of unrecovered costs to a regulatory asset and to recover such costs. The consultative process will be undertaken and completed in such a manner that will result in NS Power providing a report to the Board with the results of the consultative process and seek approval of the DDA by June 30, 2023. For greater certainty, the Board's decision in 2012 NSUARB 133 with respect to the MEUs responsibility for the payment of stranded costs continues to apply and is not affected by this agreement in principle. - The parties also agree to discuss the potential for the application, approval, and implementation of the DDA, or similar mechanism, as it relates to "New Capital Assets" and "Incremental/Decremental OM&G" as those are described in Section 4.1 of NS Power's Rebuttal Evidence (i.e. energy transition investment and costs related thereto).
Equity Ratio	- An equity thickness of 40% for rate setting purposes.
Return on Equity	- A return on equity of 9.0% for rate setting purposes.
Earnings Sharing Mechanism	- NS Power's request for a revised Earnings Sharing Mechanism is withdrawn.
Earnings Band	- An earnings band of 8.75% to 9.25% return on equity on an actual five-quarter average equity ratio of up to 40%.
Customer Charge	- As applied for, but at the 2023 customer charges amount with an agreed to reduction of 25 percent of the proposed increase and no-phase in given there will only be a one-time non-fuel/non-DSM rate increase. (Per Figure 12-2, page 99 of Direct Evidence but with 25 percent reduction to the proposed increase: Domestic Tariffs $19.17/month; Small General $21.28/month.)
Interruptible Rider	- As applied for, but at the 2023 credit amount. (Per Direct Evidence PR-01 Attachment 1, page 38: $7.486/kVa.) - The Interruptible credit will be reviewed in the next Cost of Service Study.

Distribution Adder	-	As applied for, but at the 2023 amount. (Per Direct Evidence PR-01 Attachment 1, page 35: $1.632/kVa.)
Storm Rider	-	For purposes of the years 2023, 2024, and 2025 only, as applied for, per Storm Cost Recovery Rider Direct Evidence PR-01 page 106 and PR-01 Att1v, but, modified as per Section 13 of NS Power's Rebuttal Evidence, to eliminate the volume provision of the Balance Adjustment from the Storm Rider.
	-	The parties agree that NS Power will have the option to apply to the Board for recovery of costs through the Storm Rider in the event that Level 3 and Level 4 storm restoration expense exceeds $10.2 million in 2023, $10.4 million in 2024, and $10.4 million in 2025. The Storm Rider terminates after recovery of costs from 2025.
DSM Rider	-	Implementation of the DSM Cost Recovery Rider (DSM Rider) as it was applied for, but with the amendment set out in Section 13 of NS Power's Rebuttal Evidence such that NS Power, rather than EfficiencyOne, will make the annual application for the DSM Rider to the Board and further amended to remove the last two bullets on page 8 of the DSM Rider, as committed to in the oral hearing and in Undertaking U-40. In addition, the DSM Rider charge will be incorporated within the class energy charges (i.e. not segregated on customer bills). For greater certainty, the DSM Rider's allocation of costs to customers shall be consistent with E1's approved 2023-2025 Application. For customers taking service in the Wholesale or Renewable to Retail markets, recovery of DSM costs will be through direct billing by NS Power to such customers.
Misc. Charges (incl AMI opt-out, Pole Attachment Fees, Distribution Tariff, and OATT)	-	As applied for with the exception of Pole Attachment Fees that are to be approved as per Settlement Agreement (Exhibit N-138), and the Rates for Services in NS Power's Open Access Transmission Tariff shall be capped at a maximum increase of 1.8% in 2023 and 0% in 2024. With respect to the CBAS recommendations proposed by WKM Energy Consultants, the parties agree that these issues will be left to the Board's determination in this proceeding. The MEUs will file a closing argument on these issues, following which NS Power and other parties as they see fit will have the opportunity to file a reply.
ML Transmission Asset Approvals	-	Approval of CI 43324, CI 43678, CI 45066, and CI 45067 for inclusion in rate base at their net book value as of the effective date of the Board's decision on this matter.
GRA Deferral	-	NS Power's request for a GRA Deferral is withdrawn.

Line Loss Study and COSS	-	NS Power must file a Cost of Service Study and a Line Loss Study prior to filing its next GRA or December 31, 2025, whichever is sooner. NS Power will provide for stakeholder engagement in the scoping and review of initial results, which will include consideration of bundled and unbundled services in an integrated manner as referenced in the Board's decision at para. 142 in 2021 NSUARB 126, prior to filing the final Studies. Board approval for the use of those Studies should occur as a part of the next GRA proceeding. Costs associated with the production, stakeholder engagement, and filing of these Studies may be deferred by NS Power and, subject to Board
		approval, recovered through rates subsequent to NS Power's next general rate application.
BUTU GHG Credit	-	With respect to the Wholesale Market Backup/Top-up Service Tariff GHG Credit as proposed in the evidence of Mr. Dominie, the parties agree that this issue will be left to the Board's determination in this proceeding. The MEUs will file a closing argument on this issue, following which NS Power and other parties as they see fit will have the opportunity to file a reply

[Exhibit N-155, pp. 7-10]

[56] The GRA Settlement Agreement also contained an additional schedule showing the anticipated percentage revenue increases per customer class, subject to being confirmed in a compliance filing (see Appendix B).

6.2 The Board's approach to settlement agreements

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

> [12] The Board's *Regulatory Rules* facilitate settlement discussions. The Board welcomes and appreciates the efforts of parties to, in good faith, settle issues, even where, as sometimes happens, a settlement cannot be ultimately achieved.
>
> [13] Where, as here, the Agreement is supported by representatives of all of the customer classes, the Board can have confidence that the Agreement is in the public interest.

> [14] Customers of NSPI and members of the public are, perhaps understandably, wary of the settlement process. Many of those customers and members of the public may not appreciate that by the time the hearing commences 80% of the rate hearing process has already happened. NSPI filed extensive evidence, as required by the Board, to support its rate request. Interested parties and Board Staff asked NSPI many hundreds of written questions (Information Requests), to which responses were filed.
>
> [15] All of the parties who chose to do so filed evidence, including expert evidence. Written questions (Information Requests) have been asked of and answered by interested parties who filed evidence. NSPI filed reply evidence. As noted, all of this happened before the hearing was scheduled to begin so that the parties and the Board are well informed about the case in advance of any oral public hearing.
>
> [16] The public can rest assured that the Board Members hearing the matter have also thoroughly reviewed all of the material in advance of coming to a decision as to whether to approve the Agreement as being in the public interest.
>
> [17] Settlement agreements, while relatively new in regulatory matters before the Board, are common in the litigation process. Within the Board's adjudicative mandate, for example, assessment appeals, planning appeals and other matters are often settled. In the civil courts of Nova Scotia, a much higher percentage of cases are settled than go to trial.
>
> [18] That is not to say that the Board would hesitate to reject a settlement agreement it did not consider to be in the public interest, however, it should be understood that a properly supported settlement is a success of the regulatory process, not a failure.
>
> [2008 NSUARB 140]

[58] The GRA Settlement Agreement in this proceeding was reached by the parties after the hearing was finished. This matter had a full evidentiary record containing over 30,000 pages of information and spreadsheets, including NS Power’s application, Rebuttal Evidence, Fuel Update, 19 expert reports and documents filed by the Intervenors and Board Counsel consultants, 700 Information Requests (IRs) with over 1,900 questions to NS Power and 157 IRs with over 270 questions to Intervenors, about 1,000 letters of comment from members of the public, almost 300 exhibits, and 71 Undertakings filed after the hearing.

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

> [23] …Settlement agreements do not, however, diminish the Board's duty and obligation to ensure that the terms of any such agreement result in approval of only those costs which are fair, justifiable and prudently incurred by the Utility. Further, the Board must ensure that these costs result in customer rates that are just, reasonable and in the public interest. In addition, when deciding whether to approve a settlement agreement, the Board must be satisfied that the outstanding concerns of all intervenors are adequately considered by the Board and the terms and conditions under which they consent to a settlement agreement are honoured.
>
> [*NS Power 2007 GRA* decision, 2007 NSUARB 8]

[60] While the following submission was made in the context of the Pole Attachment Fee Settlement Agreement, the Board endorses and adopts the comments in Robert Grant and Leslie Milton's Closing Brief about the important role of settlement negotiations in such proceedings:

> 26. … 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.
>
> [Eastlink/Rogers/Xplore Closing Brief, p. 7]

[61] In the Board's view, these comments are particularly relevant in the unique circumstances of this general rate application, which raised challenging issues for NS Power and its customers in the context of the need to tackle the energy transition and the impact of the limitations imposed by Bill 212.

7.0 ANALYSIS AND FINDINGS

7.1 Should the GRA Settlement Agreement be approved?

[62] Before embarking on its review of the merits of the GRA Settlement Agreement, the Board takes note of what Nancy Rubin, counsel for the Industrial Group and Dalhousie University, described as "the unique context of the settlement agreement", given that it occurred after the hearing, rather than before, and that it responded in part to legislation:

> **The Unique Context of this Settlement Agreement**
>
> This is not the Settlement Agreement that would have been reached after the filing of evidence and responses to IRs. This is not the Settlement Agreement that would have been filed after nine days of hearings and the filing of undertakings by NSPI on October 14. This is a Settlement Agreement to which the parties have been driven by the timing of legislative amendments to the ***PUA*** through Bill 212.
>
> Draft closing arguments based on the evidence and responses to undertakings were scrapped. Dalhousie University and the Industrial Group could not ignore the material impact that Bill 212 has had on the evidence and it is within that context that the parties negotiated the Settlement Agreement.
>
> [IG/Dalhousie Closing Submission, p. 3]

[63] This observation was echoed by the Affordable Energy Coalition, which noted that in response to Bill 212 it had signed the GRA Settlement Agreement to "ensure a functioning reliable electricity system, environmental goals are met and affordability" and to mitigate unintended consequences like the impact on NS Power's credit rating:

> **2. Affordability and the Settlement Agreement**
>
> The AEC signed the Settlement Agreement which limits profits to current levels in accordance with Bill 212. While we argued in our Opening Statement that we believe NSPI's profit level should not only be limited in this way but should be reduced, we signed the Settlement Agreement in view of the disruption created by Bill 212 and its effect on NSPI's financing. A stable, appropriately financed electricity system is in the interest of every customer including low income customers in order to ensure a functioning reliable electricity system, environmental goals are met and affordability. The Settlement Agreement is intended to contribute to this. Bill 212 undermined the independent regulation of the electricity system, and the unintended consequence was a downgrading in NSPI's credit rating which will increase future financing costs. In our view this disruption undermined our ability to argue for reduced profit levels at this time. In future GRA hearings we expect that we will be able to make that argument again.
>
> [Affordable Energy Coalition, Closing Statement, pp. 2-3]

[64] As noted above, the GRA Settlement Agreement obtained broad support from all major customer classes, as well as other parties who participate regularly in matters involving NS Power, including the MEUs (who supported the overall settlement with the exception of a few issues described later in this decision), the Affordable Energy Coalition and Ecology Action Centre. Moreover, most of the signatories filed Closing

Submissions noting the benefits of the agreement and requesting that the Board approve the settlement.

[65] The SBA noted his support for the agreement, asserting that its negotiation involved the balancing of various factors, including current rate affordability and service reliability weighed against meeting decarbonization goals in the future and deferring some fuel costs to later years:

> After the amendments to the *Public Utilities Act* were approved, the SBA began having discussions with NSPI about the Application and what the future might look like. The SBA, as always, was looking for an outcome that would be in the best interests of its rate classes, not only for the short term but also the medium to long term. Small General, General and Small Industrial businesses are the backbone of the Nova Scotia economy. They are impacted by the severe weather and climate change that is impacting our province and want the best for all of Nova Scotia's residents, who represent their customers, their employees and their communities. <u>The SBA believes that it is crucial that they have access to cost-effective, reliable and safe electricity, balanced with the need to reach the decarbonization goals set out by all levels of government.</u>
>
> <u>The Terms of Consensus</u> that has been provided to the Board, signed by the SBA, the Consumer Advocate, counsel for the Industrial Group and Dalhousie University, the Ecology Action Centre and the Affordable Energy Coalition, <u>represents that balance. It balances the need to reduce the increase in 2023 to as low as possible, while also not deferring all the costs to the future, which only increases overall costs.</u> Small business customers need certainty about the future in order to plan their budgets accordingly and the Terms of Consensus provides that. The stable increases, applied first to the DSM increase and then to fuel costs, allows for planning and reduces a deferral of fuel costs. There is a reality that has be acknowledged that costs are increasing across the board and electricity is no different. <u>The Terms of Consensus balances those increases with consistency and smoothing, and ensuring that ratepayers have access to all possible savings through the DDA, Storm Rider and DSM Rider.</u> [Emphasis added]
>
> [SBA Closing Submission, p. 2]

[66] The CA, William Mahody, representing all residential customers, submitted that the agreement offered several positive outcomes for residential ratepayers. He stated that the GRA Settlement Agreement complied with the *Public Utilities Act*, including the Bill 212 amendments. Mr. Mahody noted that the cost pressures from increased fuel expenses led to his support for the agreement:

> The Settlement Agreement represents the outcome of discussions among the vast majority of active participants in this matter, and it has the support of all ratepayer advocates.

> Further, the Settlement Agreement is comprehensive, addressing virtually all of the matters in contention before the Board.
>
> …
>
> Bill 212 received Royal Ascent on November 9, 2022. The discussions leading to the Settlement Agreement commenced after November 9 and all parties to the settlement were aware of the binding nature of that legislation. From the perspective of the Consumer Advocate, the Settlement Agreement was negotiated in compliance with all Statutes, including the *PUA* amendments made via Bill 212.
>
> The evidence at the hearing clearly established that the cost of fuel is exerting tremendous pressure on customer rates. That pressure will continue throughout the test period. It is that fuel cost pressure that led the Consumer Advocate to support the proposed Settlement Agreement in which the lion share of the rate increase is fuel related.
>
> …
>
> In addition to the rate increase caused by known fuel costs, the Settlement Agreement provides for the 1.8% increase referenced in Bill 212. A fair reading of the record in this proceeding – factoring in all reasonably achievable reductions to the applied for revenue requirement – led the Consumer Advocate support the 1.8% referenced in the Settlement Agreement.
>
> [CA Closing Submissions, pp. 3 & 5]

[67] The only party opposing the GRA Settlement Agreement was the Province. NRR's counsel submitted:

> 43. Bill 212 was introduced to protect ratepayers from significant shock based on unprecedented global inflationary pressures, as confirmed in the Premier's letter to the Board dated November 28, 2022. The terms of the Settlement Agreement increase rates and contravene the purpose, spirit, and intent of Bill 212.
>
> 44. Prior to the GRA proceeding, NSP returned a minimum of $125 million in profits each year for the last 12 years. These profits benefit NSP's shareholders but offer no direct benefit to ratepayers. NSP's original position in the GRA proceeding, if granted, would have further inflated these profits.
>
> 45. During harsh economic times, it is unreasonable to impose further hardship on ratepayers to enhance corporate returns. Corporate social responsibility calls for a sharing of the burden to maximize relief for ratepayers for the cost of an essential service.
>
> 46. To this end, NRR has concerns with several specific aspects of NSP's application, and the proposed resolution of these aspects by way of the Settlement Agreement.
>
> [NRR Closing Submissions, p. 9]

[68] NRR submitted that, in a number of respects, the settlement did not comply with Bill 212. In NRR's view, the use of incremental DSM costs since the last GRA, in the

proposed rate increases for 2023 and 2024, is contrary to the requirement to limit non-fuel rate increases to 1.8% over the test years.

[69] Some active participants in the proceeding did not sign the GRA Settlement Agreement, but did not oppose it, including PHP, Eastward Energy, EfficiencyOne, and Freeman Lumber.

[70] In its Closing Submission, NS Power said that the GRA Settlement Agreement should be approved:

> While a settlement agreement does not displace the Board's duty of ensuring just and reasonable rates or that the settlement is otherwise consistent with the relevant legislation, a settlement agreement such as that currently before the Board, which is comprehensive in nature and "widely supported by various parties to the proceeding," including representatives of residential, commercial, and industrial customer classes, should be given significant weight. In previous proceedings, the Board has been satisfied that settlement agreements are properly supported and are in the public interest.
>
> This wide support for the Settlement Agreement is evidenced by its signatories, which include representatives from all customer classes, as well as broadly scoped interest groups such as the Ecology Action Centre and the Affordable Energy Coalition. The diversity of interests is not only as between NS Power and its customers, but also among the customer classes and interest groups who are parties to the Settlement Agreement.
>
> Based on the comprehensive nature of the agreement and the support across all customer classes and interest groups, there should be no question that the Settlement Agreement "is in the best interest of ratepayers." The Board has previously discussed this point, finding that, where an "[a]greement is supported by representatives of all of the customer classes, the Board can have confidence that the Agreement is in the public interest."
>
> In considering the Settlement Agreement, the Board must also consider how the public interest is served by regulatory certainty and the value and importance of encouraging settlement discussions and agreements between parties with matters before the Board. …
>
> …
>
> Within the confines of the PUA Amendments, the Settlement Agreement provides a comprehensive agreement on the GRA from representatives of all customer classes and broad interest groups, all of which have a tremendous amount of experience in NS Power's matters before the Board. NS Power views the breadth and experience of the parties who are signatories to the Settlement Agreement, and the enactment of the PUA Amendments, as sufficient evidence of the just and reasonable nature of the Settlement Agreement; …
>
> [NS Power Closing Submission, pp. 9-10]

7.1.1 Findings

[71] The Board's overarching consideration in the review of the GRA Settlement Agreement, including the proposed rates and all other issues covered in it, is whether approving it results in rates that are just and reasonable, non-discriminatory and in the public interest.

[72] An appropriate starting point for the Board's review is to consider the overall context underlying the GRA Settlement Agreement presented by the Utility. The signatories to the agreement included the representatives of all major customer classes representing most of NS Power's customers, as well as other parties who participate in various NS Power matters before the Board. A number of these representatives have significant experience in proceedings involving NS Power at the Board, including general rate applications, fuel matters and the FAM Audit, annual capital expenditure (ACE) applications, annually adjusted rates, proceedings involving DSM and EfficiencyOne, the Maritime Link, rates like the BUTU, Shore Power, and the ELIADC, and renewable matters like COMFIT, renewable energy procurements, Renewable to Retail, and the NS Power Smart Grid pilot project, among other proceedings. The Board is mindful that this experience has provided these parties and their representatives with a broad understanding of NS Power, its infrastructure, and its operational realities.

[73] Moreover, the GRA Settlement Agreement represents a comprehensive resolution of many complex issues raised in this GRA, with only a few exceptions involving the MEUs remaining outstanding. Despite these outstanding issues, the MEUs executed the GRA Settlement Agreement on all other points covered by the settlement. The broad range of issues settled among the parties, considered in conjunction with the signatories

representing most of the customers joining the settlement, provides greater confidence to the Board that approving it would be in the public interest.

[74] A subtle corollary to the broad support for the GRA Settlement Agreement, and the comprehensive nature of the resolved issues, is the support the parties have provided to NS Power by reaching a negotiated settlement that attempts to address regulatory and financial concerns raised by the introduction of Bill 212 and the reaction of the credit rating agencies. While many of the Intervenors often challenge NS Power in various proceedings, including in this GRA, some of the parties stated that it was important to reach a comprehensive settlement to help ensure that NS Power remains a healthy utility, particularly as it embarks on the phase out of coal and strives to increase renewables on its system. The comprehensive settlement confirms rates that also recover increased fuel costs, introduces the FAM Riders to recover deferred fuel costs, adopts the DSM Rider and Storm Rider, confirms the Utility's return on equity needs, and supports in principle the creation of a DDA to address the realities of the upcoming energy transition. At the very least, the broad support on a wide range of issues demonstrates that NS Power had a constructive discussion with its customer representatives.

[75] The Province submits that various elements of the GRA Settlement Agreement do not comply with the recent *Public Utilities Act* amendments introduced in Bill 212. Clearly, the Board must not approve any settlement agreement that does not comply with all applicable statutes. As discussed later in this decision, the Board has found that the GRA Settlement Agreement does comply with all statutory provisions.

[76] In the Board's view, there are various aspects of the GRA Settlement Agreement that warrant approval. All of these will be discussed in greater detail later in this decision.

[77] First, the Board is satisfied that the negotiated average rate increases across all customer classes of 6.9% in each of 2023 and 2024 are reasonable and appropriate. The Board also finds that it is reasonable to defer part of the increased fuel costs to later years. The Board is keenly aware that any rate increase has an impact on ratepayers, particularly low-income customers and those on a fixed income. No rate increase is ever welcomed by ratepayers. However, the Board places significant weight on the fact that all major customer classes have negotiated these rate increase levels.

[78] It is also significant that the Affordable Energy Coalition finds the negotiated rate increases to be appropriate in the circumstances, noting the importance to low-income customers of a healthy utility. The negotiated settlement with its customer classes helps to ensure that NS Power remains a healthy utility, which is important to maintain its ability to provide reliable service and to attract capital investment for the energy transition from coal to more renewables.

[79] The request for increased rates by the Company, and the amount of the negotiated increase, must also be considered in the context that NS Power has not had a non-fuel rate increase since 2014. During the period 2014 to 2022, inflation has risen over 20%. Moreover, various federal and provincial environmental provisions require NS Power to retire coal assets and invest in infrastructure to meet 80% renewable goals by 2030 and net-zero GHG emissions requirements by 2050. While the composition of the rates is discussed later in this decision, the negotiated rates account for increased DSM

spending levels and a portion of increased fuel costs. In the Board's opinion, the introduction of the FAM Riders in 2024 and 2025 provides an appropriate balance between managing rate increases in the near future and ensuring that NS Power will be able to recover its fuel costs in a reasonable time span, bearing in mind that it may still be necessary to manage the rate impacts from implementing the riders in these years. Against that background, the Board finds that, as part of the total negotiated package in the GRA Settlement Agreement, the requested average rate increases of 6.9% in each of 2023 and 2024 are reasonable.

[80] Second, the GRA Settlement Agreement confirms NS Power's opportunity to earn a reasonable return, consistent with the regulatory compact enshrined in the *Public Utilities Act* and in the case law. Again, this is important so that the Company can attract capital to invest in its infrastructure, including more renewables. The current return on equity of 9.0% and the earnings band of 8.75% to 9.25% have been maintained, with the equity thickness for rate setting purposes being increased from 37.5% to 40%. The current Earnings Sharing Mechanism has also been kept, with excess earnings being refunded to ratepayers through the FAM, as is the case already.

[81] Third, the GRA Settlement Agreement provides an agreement in principle on the creation of a DDA, at least with respect to NS Power's thermal assets. The Board finds that this initiative is an appropriate one and in the best interests of the Utility and its customers as they engage in the energy transition. It will help enhance the transparency of the task ahead as NS Power is required by legislation to retire its thermal plants by 2030. The creation of the DDA will clearly segregate and track the financial costs associated with retiring those plants.

[82] Moreover, the creation of a DDA will allow for regulatory efficiency and provide greater flexibility to the Board to balance the cost recovery of plant retirements and decommissioning costs and affordability issues for the Utility's customers. There will not be any rate impacts in the near term from the approval in principle of the DDA.

[83] The customer representatives' support, in principle, for the establishment of a DDA, and the associated stakeholder consultation, demonstrates that there is a broad recognition of the need for a collaborative approach to the energy transition. Indeed, in its December 20, 2022, report, DBRS Morningstar noted that it would look favorably on "meaningful progress on the replacement of coal-fired plants with renewable sources in order to meet the mandated targets". The Board is pleased there is a constructive dialogue taking place in Nova Scotia about the impact on the Utility and its customers of a future without coal and other fossil fuels.

[84] Fourth, the Board also considers the establishment of the Storm Cost Recovery Rider (Storm Rider) and DSM Cost Recovery Rider (DSM Rider) as appropriate. The Storm Rider allows the recovery of all reasonable costs related to Level 3 and Level 4 storms. It is only a three-year pilot, but this will allow the parties to observe its effectiveness. It also allows an additional opportunity for assessment of system reliability and service restoration times, which are important concerns for all customers. Similarly, the establishment of a DSM Rider will provide certainty to the Utility that the costs incurred for EfficiencyOne will be recovered in a transparent way.

[85] Further, the Board considers it to be a positive outcome of the settlement process that the parties to the GRA Settlement Agreement were able to agree upon changes to various fees and amounts in NS Power's schedule of fees and charges,

including a 25% reduction to the proposed customer charges for Domestic and Small General Class customers; the addition of a Distribution Adder and an increase to the credit amount in the Large Industrial Interruptible Rider; revisions to the Distribution Tariff; and a cap of the maximum increase to the OATT of 1.8% in 2023 and 0% in 2024. Again, the agreement of the parties on such a variety of changes demonstrates that NS Power has had a productive engagement with its customer class representatives and it warrants the support of the Board.

[86] Following the filing of a large amount of evidence by NS Power and the Intervenors on cost allocation methodologies and line loss matters, the parties to the GRA Settlement Agreement agreed to defer the issues to a stakeholder engagement process, followed by the Utility filing an updated Cost of Service Study and Line Loss Study prior to the next GRA or by December 31, 2025, whichever is sooner. This recognized that there are complex issues requiring further examination by the parties. Such engagement should be supported.

[87] Taking into account the evidence and the submissions, the Board is satisfied that, considered in its totality, the GRA Settlement Agreement is in the public interest and it should be approved, except for three items discussed below. In the Board's view, the agreement provides for rates that are just and reasonable and is an appropriate resolution of many issues canvassed in the GRA. The Board also finds that the agreement complies with the requirements of Bill 212.

[88] As discussed later in this decision, the Board does not approve three items in the GRA Settlement Agreement. It does not approve NS Power's proposed AMI opt-out fee or the regulatory amortization of the Annapolis Tidal Generation Facility, which is

to remain in rate base. Further, the Board defers approval of the four Maritime Link transmission capital projects until benefits to ratepayers have been demonstrated. The Board finds these three matters are not material to the comprehensive settlement reached by the parties. NS Power may re-apply to the Board for approval of these items once conditions are met or circumstances warrant.

7.2 Interest on Deferrals

[89] The GRA Settlement Agreement provides that:

> All financing costs for deferrals are to be calculated using rates equivalent to NS Power's approved Weighted Average Cost of Capital (WACC), as approved by the Board from time to time, or as otherwise directed by the Board.
>
> [Exhibit N-155, Schedule A, p. 8]

[90] This must be considered under s. 64AB of the *PUA*, which was recently added by Bill 212:

> **Payment of interest**
>
> **64AB (1)** The Board may approve the payment of interest to Nova Scotia Power Incorporated on an outstanding balance for the Fuel Adjustment Mechanism, or any other regulatory deferral.
>
> **(2)** To be eligible for a payment of interest under subsection (1),
>
> (a) Nova Scotia Power Incorporated must demonstrate a balance is outstanding, or there is a clear demonstrated prediction for an outstanding balance, for a period of not less than twelve months prior to a request for the payment of interest; and
>
> (b) the minimum amount on an outstanding balance must be greater than one million dollars.
>
> **(3)** Interest must be calculated
>
> (a) from the date the balance is outstanding using simple interest at the Bank of Canada policy interest rate plus one and three-quarters per cent, unless otherwise directed by the Board; and
>
> (b) on a per year basis.

(4) Any request for the payment of interest on an outstanding balance must include the interest calculations for the Board for review.

[91] In response to NSUARB IR-1 (GRA Settlement Agreement) [Exhibit N-156], NS Power identified the regulatory assets and regulatory liabilities for which it seeks Board approval to recover financing costs at its Weighted Average Cost of Capital (WACC):

	Forecast Ending Balance			Forecast Average Balance	
($ Million)	**2022**	**2023**	**2024**	**2023**	**2024**
FAM Deferral	141.0	262.8	146.5	201.9	204.7
DSM Deferral	5.0	-	-	2.5	-
Renewable to Retail	1.3	1.3	1.4	1.3	1.4
Retired Hydro Assets (Harmony & Roseway, Annapolis)	22.7	20.1	17.6	21.4	18.9
Deferred Income Taxes	10.9	26.6	26.6	18.8	26.6
Total Regulatory Assets and Liabilities	**180.9**	**310.8**	**192.1**	**245.9**	**251.5**

[92] The Board notes that in the reproduction above, it has removed the rows in the table for the recovery of deferred GRA costs and the DDA, and the totals have been adjusted accordingly. Under the GRA Settlement Agreement, NS Power agreed to withdraw its claim for the recovery of deferred GRA costs, which it had shown as having no balances as a result. The removal of the DDA balances is discussed below. The deferred balance for the Annapolis Tidal Generation Facility, which is consolidated in retired hydro assets in the table, is also discussed below.

[93] NS Power is also requesting financing costs at its WACC for balances under the DSM Rider and the Storm Rider, and for the costs that the parties to the settlement agreed should be deferred for the Line Loss and Cost of Service Studies.

[94] In the NSUARB IR-1 (GRA Settlement Agreement) response, NS Power addressed why the Board should exercise its discretion under s. 64AB to allow financing costs on deferrals at NS Power's WACC. NS Power noted that its forecast WACC is the expected actual cost of financing investments based on its approved capital structure for

ratemaking purposes following a cost of service model. It said that regulatory assets and liabilities form part of its rate base, to which it is entitled to a just and reasonable return under s. 45 of the *PUA*. It also said the use of WACC is accepted utility practice, was well established in Nova Scotia and reflects the regulatory compact. NS Power submitted that, to the extent that the Board has discretion to determine a different interest rate, this must be exercised "within the confines of the statutory regime and principles generally applicable to regulatory matters, for which the legislature has assumed to have regard in passing that legislation" (*ATCO Gas and Pipeline Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4).

[95] NS Power also noted that the interest rate in s. 64AB was less than its cost of issuing new long-term bonds, meaning that if the Board determined that a deferral at that interest rate was in the best interest of customers, NS Power would be recovering less than its actual financing costs even if it were able to fund the deferral entirely with debt. It further noted that it is not able to fund deferred costs entirely with debt given the impact on its credit metrics, the potential for further credit downgrades and debt covenants in place with its bondholders limiting the percentage of debt it can have in its capital structure.

[96] NS Power advised that it must "update its GRA forecasting to reflect the decreased equity financing and increased debt financing required as a result of the legislative amendment to Section 64AA to complete its calculation of financing costs on requested deferrals."

[97] In discussing s. 64AB in its Closing Submission, NRR said the amendment was intended to make interest returns accruing from NS Power's deferrals more

accountable to the Board and more transparent to ratepayers. NRR submitted that the amendment "permits NSP reasonable interest on legitimate deferrals, while disincentivizing unnecessary deferrals on which ratepayers will be expected to pay interest."

[98] In its Reply Submission, NS Power submitted that NRR had not challenged the position or justification for its request that the Board approve financing costs for deferrals at its WACC in NSUARB IR-1 (GRA Settlement Agreement). NS Power then went on to repeat and elaborate on what it said in IR-1:

> In its response to NSUARB Settlement Agreement IR-1, NS Power provided the following:
>
> > The Bank of Canada policy interest rate plus 1.75 percent included in the legislative amendments is less than NS Power's cost of issuing new long-term bonds. The November 21, 2022 credit rating downgrade received by NS Power from S&P Global in response to the impacts of Bill 212 is expected to further increase NS Power's debt financing costs. This means that if the Board were to determine that a deferral of costs by NS Power to be recovered in the future was in the best interest of customers, NS Power would be recovering less than the Company's financing costs, even if the Company were able to fund the deferral entirely with debt.
> >
> > However, NS Power is unable to fund deferred costs entirely with debt. Given NS Power's credit downgrade by S&P Global, increasing debt would put further pressure on the Company's credit metrics and risk further downgrades. NS Power's credit rating is now at the lowest level considered to be investment grade; a further downgrade would have significant impacts on NS Power's ability to attract capital and the borrowing costs to be borne by customers. In addition, the Company has debt covenants in place with bondholders which limit the percentage of debt that the Company may have in its capital structure. As a result, NS Power is unable to materially increase the level of debt in its capital structure and must finance its investment in the Company within the Board-approved capital structure range.
> >
> > Like all companies, NS Power must pay its operating costs, including interest expense, before determining the amount of net income attributable to common shareholders. As NS Power would be paying more than the amount included in revenue requirement for interest expense under a scenario in which NS Power receives the Bank of Canada policy interest rate plus 1.75 percent on deferred costs, the financing costs included in revenue requirement remaining and attributable to common shareholders would be at a rate lower than the amount paid by NS Power in interest expense.

> The cost of equity should be higher than the cost of debt, as bondholders have a priority claim on the Company's assets as compared to equity holders. However, under the scenario in which NS Power receives the Bank of Canada policy interest rate plus 1.75 percent on deferred costs, equity holders would receive a lower rate of return than bondholders. Instead of a risk premium, there would be a discounted rate of return on equity as compared to debt.
>
> These are not just or reasonable scenarios. Holding the return of shareholders on deferrals to less than that of a bondholder will inhibit NS Power's access to capital and impair the Company's ability to fund investment in reliability and ongoing operations and to recover fuel costs over an extended period. This would limit the Company's ability to mitigate rate volatility, which NS Power undertakes for the direct benefit of customers. [Emphasis added]
>
> [NS Power Reply Submission, pp. 12-13]

[99] NS Power also submitted that NRR's Closing Submission acknowledged that s. 64AB permitted it to earn reasonable interest and submitted that the provision did not alter the standard created by s. 45 of *PUA.*

7.2.1 Findings

[100] A basic principle of regulation, as noted earlier in this decision, is the ability of a utility to recover its prudently incurred costs. Most of the deferral balances that NS Power is requesting bear financing costs at its WACC in this GRA are costs incurred in its normal course of operations. By definition, the weighted average cost of capital is the actual average carrying cost on each dollar spent, and not immediately collected, by the Utility. Those dollars are provided in part by debt, and in part by equity investment. Similar to the requirement for a down payment in order to obtain a mortgage on a home, debt is not available without the equity investment. NS Power must maintain a certain level of equity investment to comply with the terms of its debt agreements.

[101] In the normal course, balances owing under NS Power's FAM would attract interest at NS Power's WACC. However, the Board has some difficulty with NS Power's suggestion that the Board may exercise its discretion under s. 64AB of the *PUA* to allow

NS Power to recover interest on FAM balances at its WACC based on “accepted utility practice” and the “long-established practice in Nova Scotia.” If that were enough, the Board would always be justified in exercising its discretion to award a different interest rate than the Bank of Canada policy interest rate plus 1.75% specified in s. 64AB(3)(a). This would tend to make the recent amendment meaningless, which the Board cannot assume was the intent. However, the Board finds it is not necessary to consider this question because it is satisfied there is sufficient justification for exercising its discretion to allow interest on NS Power’s existing deferrals at NS Power’s WACC.

[102] The Board believes that approving the rate specified in Bill 212 on all of NS Power’s existing deferrals has the potential to have a further negative impact on NS Power’s credit ratings, and overall financial health. This would not be in the best interests of ratepayers. The Board is of the opinion that this is precisely why the legislation allowed for the Board’s discretion in assigning this rate.

[103] As shown in the table above from NS Power’s response to NSUARB IR-1, the existing deferrals all exceed $1 million, and they will be outstanding for more than 12 months. As such, the Board is satisfied that the requirements under s. 64AB(2) have been met.

[104] In considering the interest rate for these deferrals, the Board finds that NS Power’s recent credit downgrades are a relevant factor because they heighten concerns around NS Power’s credit metrics and the risk of further downgrades, resulting in the potential imposition of even more costs on ratepayers. Credit ratings are a measure of the probability an organization will default on its financial obligations. The recent downgrade of NS Power’s credit ratings commands the Board’s attention. This is an

indication that NS Power's financial health is perceived by the markets to be at a higher level of risk than it was several months ago.

[105] The Board notes NS Power's concern that setting the stated interest rate in Bill 212 on its regulatory deferrals could be setting its return on the equity invested in those balances at a lower rate than its bondholders are receiving. It appears that this would increase the risk to the financial health of the Utility. In this instance, the Board believes that stability and predictability are paramount.

[106] The Board concludes that in the circumstances, it is appropriate for it to exercise its discretion under s. 64AB(3) to set interest on the deferrals in the table above at NS Power's WACC (subject to the comments below about the Annapolis Tidal Generation Facility).

[107] Additionally, there are other reasons why approving interest at NS Power's WACC on FAM balances is appropriate. As discussed later in this decision, NS Power will defer a significant amount of fuel costs it expects to incur so rates are reduced in the current application. The parties have also agreed to discuss potential further deferrals of these costs to manage rate impacts. While it comes at a longer-term cost, the management of these rate impacts is a benefit to ratepayers in the circumstances of this proceeding.

[108] The Board also notes that FAM balances may relate to both over- or under-recoveries. In the case of over-recoveries, the balances are returned to customers with interest at NS Power's WACC. To be equitable, the interest rate paid to customers on over-recoveries and received from customers on under-recoveries should be the same.

[109] Regarding the potential future deferrals for the DSM Rider, the Storm Rider, the DDA, and the Cost of Service and Line Loss Studies, the Board finds that, considering s. 64AB of the *PUA*, the request for interest relating to these items is premature. It is not known whether any balances under the DSM and Storm Riders will exceed $1 million or if they will be outstanding for at least 12 months.

[110] While balances in the DDA would be expected to meet these requirements, as discussed later, the Board accepts the DDA in principle but it is not formally approving a DDA at this time. Any application for interest relating to the DDA should proceed at the time of seeking formal DDA approval and following the agreed upon stakeholder consultative process.

[111] In expert evidence and during the hearing, securitization was presented as a possibility to mitigate the significant carrying costs associated with future retirement of NS Power's thermal plants. The Board sees this as a possibility to reduce the carrying costs on the DDA in the future. However, there is due diligence that would need to be completed to determine if this is a viable option for NS Power, and in the best interests of customers.

[112] Finally, for all the items for which the Board is not approving a rate for the recovery of interest at this time, the circumstances at the time of a future application for interest may be different, particularly relating to NS Power's credit ratings and access to debt financing. This, along with other factors, may have an impact on the exercise of discretion about the appropriate interest rate on deferrals.

[113] In the case of the Annapolis Tidal Generation Facility, and as discussed later in this decision, the Board is not approving the creation of a regulatory asset at this

time as NS Power has not addressed the concerns the Board expressed in denying its previous application to have the facility declared not used and not useful (M10013).

[114] For the existing deferrals approved for the recovery of interest at NS Power's WACC discussed above, the Board directs NS Power to provide forecasted interest calculations to the end of 2024 in its compliance filing.

7.3 2023 and 2024 6.9% rate increases

[115] In a general rate application, NS Power forecasts its costs for the next year, which is referred to as the test year. In an application that seeks to set different rates over multiple years, such as the present proceeding, the forecast covers a number of test years. In either case, the costs in the test years are reviewed in considering the application. If they are reasonable and prudent, they are included in the total costs the Company may recover in the rates it charges to its customers. The revenue needed to cover these reasonable and prudent costs is NS Power's "revenue requirement."

[116] Because the rates charged to customers must be fair, not only as between NS Power and its customers, but also as between NS Power's various customer classes, NS Power's costs are allocated to each class under a cost of service study. Class rates are then designed to recover the portion of costs allocated to that class (i.e., the revenue requirement for that class).

[117] Once rates are set, actual costs will likely vary between rate cases, but rates will not. Rates remain the same until the next general rate application when the Utility's costs in the test year or years at that time will again be used to determine a new revenue requirement upon which new rates will be set.

[118] There are also other factors that influence rates. For example, if a utility's costs remained the same between rate applications, but demand for its services increased, rates would be reduced, everything else being equal. Conversely, reducing demand tends to increase rates if costs remain the same.

[119] NS Power's fuel and purchased power costs are an exception. These costs are recovered under NS Power's approved FAM. As designed, the FAM requires the setting of a base cost of fuel rate at least every two years. Annual adjustments account for the variation between actual fuel and purchased power costs and the fuel related revenues recovered under the base cost of fuel rate. Fuel stability plans covering multiple years have sometimes altered the way this mechanism works but the intent is to ensure that NS Power's customers pay only the reasonable and prudent fuel costs actually incurred.

[120] Figure 10-1 in NS Power's revised application [Exhibit N-16], filed on February 18, 2022, shows its forecast revenue requirement for 2022 ($1,592,800,000), 2023 ($1,685,300,000) and 2024 ($1,665,900,000) by cost category. NS Power's standardized filing requirements for regulated statements of earnings [Exhibit N-20, FOR-01, Attachment 1] has similar information, but also includes the 2014 restatement of NS Power's compliance filing in its last general rate application. Part of FOR-01, Attachment 1, which includes NS Power's restated 2014 compliance filing and its proposed rates in the application (2022-2024), is reproduced below:

Nova Scotia Power Inc. **FOR-01**
Regulated Statements of Earnings
Years Ended December 31st
Millions of Dollars

2022-2024 Financial Outlook

	(1) Compliance Restated 2014	(7) Proposed Rates 2022	(8) Proposed Rates 2023	(9) Proposed Rates 2024
Revenue				
Electric	1,247.8	$1,558.3	$1,649.8	$1,629.7
Other	23.2	34.5	35.4	36.1
Total	1,271.0	1,592.8	1,685.3	1,665.9
Cost of Operations				
Fuel for generation and purchased power	450.7	682.5	683.2	702.7
FAM Fuel Cost Deferral	-	-	52.5	-
Fixed Cost Recovery adjustment	16.5	-	-	-
Rate Stabilization Adjustment	(35.3)	-	-	-
Settlement Adjustment	(13.8)	-	-	-
Cost of goods sold	1.0	-	-	-
Operating, maintenance and general	282.3	283.6	288.8	297.4
Demand Side Management	-	41.0	39.0	39.0
Grants in lieu of property taxes	38.4	42.8	43.5	44.3
Depreciation and accretion	202.2	251.8	265.3	280.4
Total Cost of Operations	942.1	1,301.6	1,372.3	1,363.8
Earnings From Operations	328.9	291.2	312.9	302.1
Regulatory amortization	22.1	11.4	12.1	10.5
Allowance for funds used during construction, FAM and RS interest	(12.4)	(17.9)	(27.2)	(21.7)
Earnings Before Interest and Tax	319.3	297.6	328.0	313.3
Interest and Other expenses	153.1	122.0	121.3	116.3
Earnings Before Income Tax	166.2	175.6	206.7	197.0
Corporate income tax	34.8	22.1	14.4	(16.5)
Net Earnings Before Dividends	131.4	153.4	192.2	213.5
Preferred dividends	8.0	-	-	-
Net Earnings Applicable to Common Shares	**$123.4**	**$153.4**	**$192.2**	**$213.5**

[121] Compared to 2014, NS Power's costs show notable increases in fuel and purchased power, depreciation and accretion, and net earnings (shown as "Return on Equity" in Figure 10-1 [Exhibit N-16]). Although it is dealt with in more detail later in this decision, the Board also notes that no demand side management costs are included in the restated 2014 compliance filing, but they were included in the revenue requirements

for the test years in the current application. Operating, maintenance and general (OM&G) costs are essentially flat from those embedded in 2014 rates to those proposed in 2022 rates. These costs increase slightly through the test period.

[122] There is an uneven distribution of cost increases in the test years. Overall, the revenue requirement increases approximately $320 million from 2014 to 2022, increases nearly $100 million again in 2023 and drops approximately $20 million in 2024. To manage this volatility, NS Power's application proposed rate increases that would be smoothed over 2022-2024 for overall average rate increases of 3.6% in each of the three years.

[123] By the time NS Power filed its Fuel Update on September 2, 2022, its forecast fuel costs had ballooned and were projected to be $681.5 million more than initially forecast in its application. NS Power summarized these changes in Figure 1 in the update [Exhibit N-103]:

Figure 1 – Summary of Fuel and Purchased Power Changes 2022-2024*

Change in Fuel Costs (May 2021 vs June 2022) ($ Million)				
	2022	2023	2024	Total
GRA Total Fuel Costs	682.5	683.2	702.7	2,068.4
Fuel Update Costs	933.5	875.9	940.5	2,749.9
Variance	251.0	192.7	237.8	681.5

* Costs include GHG compliance expense for 2022.

[124] Fortunately, the Province of Nova Scotia provided relief to customers on GHG compliance expenses to the end of 2022, which is expected to reduce the impact of NS Power's fuel cost update by approximately $165 million. Even with this benefit, a large amount of forecast extra fuel costs remains to be addressed. Despite this, NS Power did not propose to adjust the amount of fuel costs to be recovered for 2023 and

2024 from what was sought in the original application. Instead, it proposed to collect under-recovered fuel costs to the end of 2022 over a three-year period from 2023-2025. NS Power also proposed to address the anticipated under-recovery of fuel costs during the test years through annual FAM Riders in 2024 and 2025.

[125] In Undertaking U-2 [Exhibit N-152], NS Power provided a “benchmark proposal” as a frame of reference for comparing some cost recovery scenarios it was asked to produce. The benchmark proposal assumed no rate changes in 2022, a resetting of the smoothing for the 2023 and 2024 base fuel costs (based on the fuel costs for those years in its original application), the smoothed recovery of under-recovered fuel costs to the end of 2022 in 2023-2025, and DSM in the amounts approved in the Board’s *2023-2025 DSM Plan* decision in M10473.

[126] Under the benchmark proposal, overall average rate increases of 6.9% were shown for 2023 and 2024. However, the benchmark proposal would have also required that sizeable adjustments to FAM Riders be considered for the forecasted under-recovery of fuel costs in 2023 and 2024, or a significant projected deferral by 2025.

[127] The parties who signed the GRA Settlement Agreement propose that the Board approve an overall average rate increase of 6.9% in each of 2023 and 2024. This is the same increase shown in the benchmark proposal provided in response to Undertaking U-2, but the share of fuel and non-fuel components is different because of the rate increase limitations in the *PUA* amendments. Like the benchmark proposal, and despite the recovery of more fuel costs, it also leaves a significant amount of forecasted fuel costs unaddressed (including the unrecovered balance to the end of 2022).

[128] NS Power provided information on potential impacts from this deferred recovery of fuel costs in response to NSUARB IR-4 (GRA Settlement Agreement) [Exhibit N-156]. The parties propose that these costs be addressed through the FAM Riders in 2024 and note:

> As the rate increase required to collect under-recovered fuel amounts in a 2024 AA/BA Rider is material for all or certain of the customer classes, the parties will work in a good faith manner to defer a portion of the impact of the increase and costs to 2025 or an additional period as may be reasonable and appropriate.
>
> [Exhibit N-155, p. 8 (PDF)]

[129] The table below compares the fuel, non-fuel and overall average rate increases under NS Power's application, the benchmark proposal in Undertaking U-2 and the GRA Settlement Agreement. As discussed, the table does not account for the recovery of all the fuel costs forecasted in the Fuel Update in either the benchmark proposal scenario or as proposed under the GRA Settlement Agreement. It should also be noted that the non-fuel numbers in the original application assumed DSM costs based upon the approved DSM budget for 2022 and estimated budgets for 2023 and 2024. Higher DSM budgets were approved by the Board after NS Power's application was filed for EfficiencyOne's 2023-2025 DSM Plan (M10473). The higher DSM amounts are included in the Fuel Update and GRA Settlement Agreement rate increases shown:

Rate Component	Application (Smoothed) Figure 2-4 Exhibit N-16 (Estimated DSM 2023-24))			Fuel Update U-2, Figure 12-5, Tab 1 (Benchmark Proposal) Exhibit N-152 (Approved DSM)		Settlement Agreement Schedule "B" Exhibit N-155 (Approved DSM)	
	2022	2023	2024	2023	2024	2023	2024
Non-fuel	2.8%	2.8%	2.8%	5.2%	5.2%	5.4%	0.3%
Fuel	0.8%	0.8%	0.8%	1.7%	1.7%	1.5%	6.6%
Total	3.6%	3.6%	3.6%	6.9%	6.9%	6.9%	6.9%

7.3.1 Overall Increase

[130] The *PUA* amendments place a cap on rate increases in this proceeding, subject to limited exceptions. In its response to NSUARB IR-2 (GRA Settlement Agreement), NS Power explained the approach that it took to develop rates to follow this restriction:

> NS Power reduced each above-the-line (FAM customers) rate class's revenue responsibility for non-fuel costs before the Interruptible Rider Adjustment and allocation of DSM costs proportionately to each class's relative share in the total non-fuel/non-DSM cost revenue requirement before the Interruptible Rider Adjustment and DSM costs as filed in the GRA. This resulted in an overall average 1.8 percent non-fuel/non-DSM rate increase in 2023 and 0 percent in 2024, thereby establishing the revenue requirement for rate-setting purposes pursuant to the amendments to the Public Utilities Act (the capped revenue requirement).
>
> [Exhibit N-156]

[131] In essence, NS Power reduced its revenue requirement for non-fuel and non-DSM costs for rate setting purposes to meet the legislated cap using the costs in its original application. It did not restate those costs to show whether, or how, it might reduce them to achieve the rates being proposed.

[132] In its Closing Submission, NS Power said the proposed rates under the GRA Settlement Agreement produced a forecasted shortfall in non-fuel revenues of $70 million over 2023 and 2024 compared to its benchmark proposal in Undertaking U-2. It submitted that the evidence presented to the Board in this proceeding did not justify such a significant reduction to its revenue requirement.

[133] NS Power relies on the ScottMadden and Gartner studies it filed in this proceeding as demonstrating the reasonableness and prudency of its OM&G costs. NS Power noted these costs were essentially flat between 2014 and 2022 despite inflationary pressures of about 20% through this period. It also noted its forecast for these costs did

not include the high inflationary pressures that have arisen in 2022 since its forecast was prepared.

[134] In his evidence [Exhibit N-55], Board Counsel consultant, Paul Burnell, FSA, FCIA, Plenus Actuaries and Consultants, noted that interest rate levels had increased sharply since the preparation of the pension costs used in the rate application. He said pension costs in the application would be lower at current interest levels. In its Closing Submission, NS Power said it expects that any pension cost savings that may arise from interest rate increases would be more than offset by increased interest expense and the cost effects of inflation, as well as increased financing costs arising from the *PUA* amendments.

[135] The parties who signed the GRA Settlement Agreement supported NS Power's approach to achieving a reduced revenue requirement for rate setting purposes and the proposed rates. In his Closing Submission, the CA said:

> In addition to the rate increase caused by known fuel costs, the Settlement Agreement provides for the 1.8% increase referenced in Bill 212. A fair reading of the record in this proceeding – factoring in all reasonably achievable reductions to the applied for revenue requirement – led the Consumer Advocate [to] support the 1.8% referenced in the Settlement Agreement.
>
> [CA Closing Submission, p. 5]

[136] While they supported the proposed rates, some GRA Settlement Agreement signatories did not fully agree with NS Power's assessment of the impact of the *PUA* amendments on its costs. The Closing Submission filed by the Industrial Group and Dalhousie University noted:

> NSPI's filed GRA was predicated on a certain revenue requirement, with each expense and capital investment broken down and itemized. At this point, NSPI "has not yet determined how resources will be redeployed to comply with the requirements of Bill 212." NSPI has stated that it will need to operate with approximately $70 million in revenue reduction over its forecast.

> With the terms reflected in the Settlement Agreement, the Industrial Group believes that this reduction can be achieved. First, a material portion of the revenue requirement reduction is addressed through the reduction in equity thickness. Additionally, interest rates have continued to rise with a correlative beneficial effect on pension expenses. The evidence was that the dollar value of the reduction in service costs for NSPI's revenue requirement for pensions in 2023 and 2024, based on an increase in interest rates of 1.8% to 2.4% would be $6.8 million to $11.3 million in 2023 and $7.0 million to $11.6 million in 2024. In cross-examination, NSPI agreed with Mr. Burnell's assessment, with its own actuaries confirming those ranges were reasonable. There is also an approximate $3 million reduction in the Maritime Link assessment in 2023, subject to the Board's decision in that application (M10708).
>
> The other lever for NSPI to control costs relates to capital investments and associated return and depreciation. Evidence during the hearing suggested considerable uncertainty with the capital project addition forecast in the GRA to the effect that a number of projects are not yet applied for, or not yet approved. NSPI may choose to manage the timing of these projects, if satisfied they can be deferred without sacrificing reliability.
>
> [IG/Dalhousie Closing Submission, pp. 3-4]

[137] In their Reply Submission, the MEUs stated:

> The MEUs agree that the one-time 1.8 percent non-fuel, non-DSM increase agreed to in the Settlement Agreement is just, reasonable, and prudent in the context of this case. However, NS Power's alleged "forecast shortfall… of approximately $70 million" needs to be understood both in relation to the forecast revenue requirement approved as part of NS Power's most recent 2013/14 General Rate Application ("GRA"), and the differences between NS Power's 2022 GRA forecast as filed and the actual 2022 year-to-date results discussed in the hearing.
>
> [MEUs Reply Submission, p. 4]

[138] The MEUs went on to note that the forecast used to set rates for 2014 varied considerably from the costs that were actually incurred, resulting in an over-recovery of expenses (subject to over-earnings being returned to ratepayers). The MEUs observed that until 2020 and the COVID-19 pandemic, NS Power was able to earn at the top of its earnings range, even after finding room to absorb demand side management costs when the earlier DSM Rider was removed by legislation in 2015. The MEUs then compared NS Power's 2022 GRA forecast to actual results noting again that actual results were better than forecast.

[139] The MEUs concluded on this point by saying:

> Given the foregoing, and consistent with the Closing Submissions of the Industrial Group and Dalhousie at pages 3-4, the MEUs believe that the $70 million reduction in revenue requirement as compared to NS Power's original filing can be achieved. In the next GRA, it will be important for the Board and all parties to carefully review and compare NS Power's actual financial performance in 2022, 2023, and 2024 with the forecasts originally filed in this GRA proceeding to fully understand the areas where and how cost savings were achieved, in order to identify all opportunities to keep the non-fuel costs in NS Power's rates as low as reasonably possible on behalf of ratepayers for 2025 and beyond, as the Province sought to do with the PUA Amendments.
>
> [MEUs Reply Submissions, pp. 7-8]

[140] In its Closing Submission, the NRR argued that the GRA Settlement Agreement increased rates and contravened the "purpose, spirit and intent of Bill 212." It expressed concerns with several aspects of the GRA Settlement Agreement.

[141] In respect of fuel and purchased power costs, NRR noted that the Province has already reduced the impact of escalating fuel costs through forgiveness of GHG costs and was continuing to explore further ways to mitigate these costs. However, NRR argued that the extra fuel costs falling on ratepayers were largely due to the cost of having to replace undelivered Maritime Link energy in a high-cost period and NS Power's profits should "bear at least a portion of inflated fuel costs that are being passed along to consumers."

[142] In terms of NS Power's non-fuel costs, NRR said the proposed non-fuel rate increase did not properly account for DSM costs. Rather than allow for an increase to cover the full annual amounts of DSM costs approved by the Board (M10473), NRR submitted only the difference between DSM costs approved for 2022 and those approved for 2023 and 2024 should be recovered from ratepayers under the legislated rate cap.

7.3.2 Fuel Increase

[143] As noted above, NRR expressed concern about the cost of replacing undelivered Maritime Link energy and suggested that at least a portion of this should not be passed along to customers. It did not suggest what that portion should be or how it should be calculated.

[144] Evidence filed on behalf of the CA by Resource Insight raised a similar concern. It noted the NS Block of energy did not materialize as contemplated in the 2020-2022 Fuel Stability Plan and since the date of the Acceleration Agreement that triggered the commencement of the NS Block on August 15, 2021. Resource Insight recommended that the Board reduce the fuel adjustment by a specific amount determined from its calculations of the additional cost, net of holdbacks ordered by the Board. Alternatively, Resource Insight said the Board could defer this question to the 2020-2021 FAM audit, but it recommended a balance reduction in this proceeding subject to an adjustment in either direction in that audit.

[145] In its Rebuttal Evidence, NS Power submitted that its general rate application was not a prudency review of its historical fuel costs and that such matters should be deferred to a FAM audit. NS Power went on to say that the Board had already determined that there was no imprudence in NSP Maritime Link Incorporated's (NSPML) decision to proceed with the completion of the Maritime Link on the originally scheduled timeline and that the Maritime Link had been determined to be "used and useful" by the Board. NS Power said:

> The Maritime Link has and will continue to be a significant contributor to NS Power's ability to meet its decarbonization goals in a timely way which benefits customers. NS Power understands and shares customer frustrations around the delay in the delivery of the NS Block and energy from Muskrat Falls; however, NS Power had no control over the circumstances which gave rise to those delays.

> NS Power has sought to mitigate impacts associated with the delay in the timing of the delivery of NS Block. The Company will still receive the energy for which it contracted as part of the Maritime Link project. NS Power has negotiated an additional agreement (Acceleration Agreement) with Nalcor in August 2021 which secured delivery of the NS Block energy prior to the commissioning of the LIL. In the absence of the Acceleration Agreement, customers would not have the benefit of the NS Block energy obtained prior to the commissioning of the LIL. As such, rather than exposing them to delay risks and costs, customers have received benefits under the Acceleration Agreement since August 2021. Under the Acceleration Agreement and the terms of the Energy & Capacity Agreement, Nalcor is also incentivized to replace the shortfall of the NS Block energy as soon as possible.
>
> [Exhibit N-102, p. 156]

[146] The Maritime Link project was approved by the Board in 2013 [2013 NSUARB 154 and 2013 NSUARB 242]. The application for the approval of that project was presented to the Board under the *Maritime Link Act*, S.N.S. 2012, c. 9 and the *Maritime Link Cost Recovery Process Regulations*, N.S. Reg. 189/2012. Under this legislation, the Board was required to hold a hearing and approve the project if, on the evidence and submissions provided, the Board was satisfied the project represented the lowest long-term cost alternative for electricity for ratepayers in the province that was also consistent with obligations under the *Electricity Act* and any obligations governing the release of GHG and air pollutants under the *Environment Act*, the *Canadian Environmental Protection Act* (Canada) and any associated agreements. Subject to several terms and conditions, the Board concluded the application met those requirements based on the evidence presented in the hearing.

[147] In 2017, when NSPML applied for its first interim assessment to begin recovering costs from NS Power under the *Maritime Link Act*, the Board determined that the Maritime Link would be “used and useful” in accordance with regulatory principles [2017 NSUARB 149]. In its decision, the Board noted that no Intervenor had suggested that NSPML was imprudent in continuing construction of the Maritime Link in the face of Nalcor’s announced delay in completion of the Muskrat Falls Generating Station.

[148] In 2022, the Board approved NSPML's application for the Maritime Link final project costs [2022 NSUARB 18]. In that decision, the Board noted that the planning and development of the Maritime Link Project was a significant endeavour, which NSPML managed to complete without the substantial cost overruns and construction delays that plagued many other energy mega-projects across North America.

[149] The Board notes the delivery of renewable energy over the Maritime Link continues to be a component of the Province's renewable energy standards governing the amount of renewable electricity that NS Power must supply to its customers. The *Renewable Electricity Regulations* require NS Power to deliver "20% of the electricity generated by the Muskrat Falls Generating Station if the Muskrat Falls Generating Station and associated transmission infrastructure is completed and in normal operation and the UARB has approved an assessment against NSPI under the *Maritime Link Act* and its regulations" to meet the renewable electricity standard through to the 80% requirement in 2030 and beyond.

[150] However, since the first interim assessment approval in 2017, the delayed delivery of the NS Block has been an ongoing concern.

[151] At the risk of oversimplifying the complex contractual arrangements in place between Emera and Nalcor for the Muskrat Falls project and the Maritime Link, NS Power's customers are, in effect, paying for the delivery of the NS Block energy but not receiving the energy in the timeframe contemplated. As such, NS Power must generate or procure other energy to replace the missing NS Block energy. Ultimately, NS Power expects to receive the NS Block and those missed deliveries will be made up later and displace energy that would otherwise have been procured or generated at that time.

[152] To the extent that current customers are paying for NS Block energy that will be delivered later, this can create a timing mismatch between the cost that is being paid and the benefit that is being produced. This can create unfairness in the costs paid by customers in different time periods, giving rise to so-called "intergenerational equity" concerns. These concerns arise from the delayed delivery of the NS Block even if NS Power is made whole by future deliveries. The longer the period between the missed delivery and the make-up delivery, the greater these concerns. To address this in some way, the Board has required that a portion of the assessment NS Power is required to pay to NSPML be held back.

[153] In 2017, an annual $10 million holdback was established. This was based on a conservative estimate of the economic benefit of the Maritime Link to NS Power's customers on an annual basis. In 2022, when final project costs were formally approved, a form of holdback was continued to provide some ongoing protection to ratepayers. Each month, beginning April 1, 2022, NS Power was required to hold back $2 million from the approved assessment to pay for the cost of replacement energy if at least 90% of the NS Block (including Supplemental Energy) was not delivered. That arrangement was continued by the Board in its approval of NSPML's 2023 cost assessment [2022 NSUARB 191]; however, the Board has directed that a proceeding be initiated to determine the disposition of holdback funds from 2022 and the administration of the holdback, generally, on a prospective basis, including any potential increase of the holdback.

[154] Depreciation and the amortization of deferred financing charges for the Maritime Link were also initially limited, but commenced on June 1, 2020, to ensure timely payment of the Government of Canada guaranteed debt for the Maritime Link and that

there be no default under the provisions of the credit arrangements and the Federal loan guarantee.

[155] While these various mechanisms may, in some small way, ameliorate intergenerational equity concerns, the question remains whether the replacement energy NS Power will receive from Nalcor will have the same economic value as it would have if it had been delivered on time. In its decision approving the final project costs for the Maritime Link project, the Board observed that the risk of prudently administering the redeliveries of the NS Block energy under the Acceleration Agreement and the Energy and Capacity Agreement rested on NS Power. The Board said it considers that the FAM audit process is the appropriate forum to review the economic value received by ratepayers from transactions involving the re-delivery of the NS Block (including Supplemental Energy) and Nalcor Market-priced Energy. The Board continues to be of this view.

[156] The Board notes that FAM audits are an integral component of NS Power's fuel adjustment mechanism. The FAM Plan of Administration provides that an audit of NS Power's fuel and purchased power costs be undertaken every second year. These audits are comprehensive and conducted by a qualified independent firm retained by the Board that considers fuel and energy procurement, fuel management and generation production, including:

- fuel and purchased power costs;
- operational availability and capacity factors for the generation fleet;
- fuel handling, quality control, inventory management and performance monitoring;
- the dispatching of resources;

- the review of contracts for prudency and compliance with NS Power's Fuel Manual;
- the use of hedging;
- system sales;
- the review of internal and external audit reports on the procurement of fuel and purchased power; and
- the calculation of base fuel costs and FAM adjustments.

[157] An audit report is ultimately filed with the Board and considered in a public hearing during which interested parties have an opportunity to question the auditor's findings and recommendations and present the Board with additional information. The Board may disallow NS Power's fuel costs if they are determined to have been imprudently incurred.

[158] Given this existing process, the Board does not agree that the fuel costs in this proceeding should be reduced to account for the possibility of ongoing late deliveries in the test years or to address historical differences. This issue may be considered in future audits.

[159] If the recovery of fuel and purchased power costs under the GRA Settlement Agreement, and approved in this decision, require changes to NS Power's FAM Plan of Administration, NS Power is directed to file the updated plan with its compliance filing.

7.3.3 Non-Fuel Increase

[160] Under the GRA Settlement Agreement, the overall non-fuel rate increases are split between DSM and other non-fuel items as follows:

GRA Settlement Agreement Non-fuel Rate Increases		
	2023	**2024**
DSM	3.6%	0.3%
Other Non-fuel	1.8%	0%
Total Non-fuel	5.4%	0.3%

[Exhibit N-156, NSUARB IR-3, Attachment 1, p. 1]

[161] While the parties appear to agree that the *PUA* amendments restrict non-fuel rate increases in this application to 1.8% except for increases relating to fuel and DSM, they have different interpretations of the meaning of "an increase respecting demand side management approved by the Board" in s.64A(3)(b). A brief review of the history of NS Power's recovery of DSM costs is helpful in putting this disagreement in context.

[162] In 2009, NS Power requested a DSM Rider for 2010 and beyond. The Board approved a rider that was based on the DSM program costs for the year and a true-up mechanism to account for any difference between the amount billed under the rider and approved program costs [2009 NSUARB 116]. As a result, DSM costs were not included in NS Power's base rates but were instead recovered through a rider that was adjusted each year. This practice continued until 2015 when it was eliminated by s. 12 of the *Electricity Efficiency and Conservation Restructuring (2014) Act*, S.N.S. 2014, c. 5:

> **Approvals of no effect**
>
> **12** **(1)** Effective on and after January 1, 2015, any approval with respect to Demand Side Management Cost Recovery Charges or the Demand Side Management Cost Recovery Rider in Nova Scotia Power Incorporated's rates and tariffs approved by the Review Board in its order dated February 1, 2013, is of no force and effect.
>
> **(2)** For greater certainty, subsection (1) does not apply to electricity sold by Nova Scotia Power Incorporated before January 1, 2015.

[163] The Board notes that the Order dated February 1, 2013, referenced in subsection 12(1), is the Board's Order approving NS Power's rates in its last general rate application [*2013-2014 GRA* decision] (M04972). The recovery of DSM costs through the periodically adjusted rider instead of in its base rates (which could only be adjusted in a general rate application) and its subsequent elimination by legislation, is the reason for the Board's earlier observation in this decision that DSM costs were not included in the restated 2014 compliance filing amounts shown in Exhibit N-20, FOR-01, Attachment 1.

[164] The *Restructuring (2014) Act* also amended the *PUA* to add the electricity efficiency and conservation franchise provisions under which the current franchise holder, EfficiencyOne, continues to operate. Transitional provisions deemed an agreement between the franchise holder and NS Power to exist for the supply of DSM to the end of 2015. Section 79R(3) also stipulated that NS Power's costs under this deemed agreement must be recovered over an eight-year period beginning January 1, 2016.

[165] On October 7, 2015, the Board approved EfficiencyOne's DSM Plan for 2016-2018. In its Order, the Board directed NS Power to file a proposed accounting treatment and cost recovery for the DSM programs in 2015 and under the 2016 to 2018 plan (M06733).

[166] In a letter to the Board dated December 18, 2015, NS Power advised it intended to expense the 2016 amortization amount for the 2015 DSM program in its 2016 operating costs. It also advised that it was not applying for a general rate application for 2016 and believed it could absorb the associated 2015 and 2016 DSM program costs in the revenue generated from its existing rates. It said it had not yet determined whether it

could absorb DSM amounts for the years beyond 2016 and had not yet determined whether it would file a general rate application for 2017.

[167] In an IR from Board Counsel consultant, Multeese Consulting, in that proceeding (M07151), NS Power was asked about the amount of DSM costs in its current rates. NS Power responded:

> Response IR-6:
>
> NS Power does not consider its current non-fuel rates to contain DSM funds. Although there is currently no portion of the revenue requirement from the previous GRA that is collected explicitly to pay for DSM programming, NS Power has considered the sum of its forecasted expenses for 2016, including the 2016 DSM program costs, when making the determination that it would expense 2016 DSM costs and absorb the recovery risk of those costs. The Company will make a similar determination when considering whether to apply for a GRA for 2017-2019 as contemplated under the *Electricity Plan Implementation (2015) Act*. If the Company does not apply for a GRA, it has requested until June 30, 2016 to finalize its Cost Recovery proposal for post 2016 DSM costs.
>
> [M07151, Exhibit N-8]

[168] The Board's decision in the matter, dated April 11, 2016, denied NS Power's request to defer the determination of its accounting treatment and recovery of its 2017, 2018 and 2019 DSM expenditures. The Board reasoned that since NS Power had decided not to apply for a general rate application in 2016 (and was precluded from changing its general rates earlier than January 1, 2020, under the *Electricity Plan Implementation (2015) Act*, S.N.S. 2015, c.31, s.18), NS Power had decided to absorb 2017 to 2019 DSM costs within its existing rates. Additionally, the Board noted that funds relating to a fixed cost recovery amortization, the s.21 tax deferral and 2008/09 DSM amortization continued "to be collected in current rates even though they are no longer required for those purposes, and could be available to fund annual DSM costs."

[169] In its Closing Submissions in this proceeding, NRR referred to the Board's decision in M07151 and, noting that NS Power did not raise the issue again in subsequent

hearings on DSM costs, suggested this meant that NS Power accepted that “DSM costs were part of rates in those years.” NRR went on to conclude:

> NRR submits that the DSM amount referenced in the Settlement Agreement is not in keeping with the *PUA*, and that only amounts *incremental* to the 2022 year, recently approved by the UARB in M10473, were what the Legislature intended to include in rates.
>
> [NRR Closing Submission, p. 15]

[170] NS Power’s position on this issue was expressed in its response to NSPI (NSDNRR) IR-4 (GRA Settlement Agreement) [Exhibit N-157]. NS Power said the full Board-approved amount for DSM spending and the “incremental amount” were in fact the same for rate setting purposes for 2023 and 2024. In making this statement, NS Power noted that the rate rider that was in effect prior to 2015 was removed and that:

> … although the Company has been able to “absorb” the cost of DSM programming in Board-approved rates since the discontinuation of the DSM Rider in 2015, this was achieved through variances in revenue and cost forecasts from those underpinning 2014 rates. There is no direct linkage to the changes in cost and revenue amounts since 2014 to annual class DSM programing approved by the Board.
>
> [Exhibit N-157, IR-4, p. 2]

[171] NS Power’s IR response went on to address the Board’s earlier comments about the amounts included in rates in 2014 for the amortization of certain deferrals that were no longer needed for those purposes being available to offset DSM costs after the removal of the earlier DSM rider. NS Power stated:

> This consideration reinforces why it is the full forecast cost of DSM programs which must be included in the proposed rate increases as provided through the Settlement Agreement, and not a lesser amount. In its application the Company has appropriately removed past costs from its revenue requirement, such as the Section 21 tax amortization referenced in the Board Decision.
>
> Effectively, for a reduced incremental approach to DSM spending to be considered the Company would also need to reinstate costs from the prior GRAs, even though these costs are no longer borne by the Company. Such an approach is illogical and inconsistent with well-established regulatory practice in Nova Scotia for the setting of the utility’s revenue requirement and determination of required rate increases and, as such, is not being proposed by the Company.

> What is being proposed are rate increases which provide for the full recovery of DSM program costs through a DSM Rider beginning in 2023, as was the case prior to 2015. This recognizes that these are Board-approved expenditures (M10473), which are not controlled or managed by NS Power, and are in no part included in the Company's general rates.
>
> [Exhibit N-157, IR-4, p. 3]

[172] The Board accepts that DSM costs were not included in the revenue requirement used to set NS Power's base rates (or general rates as NS Power referred to them in the passage above) in its 2013-2014 GRA. The revenue needed to recover DSM costs was recovered through a separate DSM Rider that was subsequently eliminated by legislation. The Board also accepts that, since the DSM Rider was eliminated in 2015, NS Power has paid for DSM costs with revenue collected from its customers through its general rates.

[173] Whether the rate increase above the 1.8% rate cap that may be allowed "respecting demand side management approved by the Board" is to be determined relative to the amount included in base (or general) rates in 2014 (none) or actual DSM costs immediately before the passage of Bill 212 ($39 million approved in matter M09096) is a question of statutory interpretation. The Board estimates that this difference in interpretation accounts for approximately 2.7% of the proposed 6.9% increase in 2023 and does not contribute at all to the proposed 6.9% increase in 2024. That increase only includes the additional $4.4 million in approved DSM spending (M10473) between 2023 ($53.1 million) and 2024 ($57.5 million) in the proposed non-fuel increase in that year.

[174] Notwithstanding the well-recognized statutory interpretation framework discussed previously, none of the parties in this proceeding presented the Board with a robust statutory interpretation analysis. NS Power and NRR did little more than refer to the factual circumstances relating to the recovery of DSM costs by NS Power and state

their positions on what the legislation allowed or intended. For the most part, the other parties in the proceeding did not explicitly address this issue.

[175] While submitting that NS Power's position was a reasonable interpretation of the legislation, the CA left the matter for the Board's determination:

> The DSM Rider represents a portion (approximately 3.5%) of the proposed rate increase. In its reply to NSDNRR IR-4 (N-157), NS Power provided its view of how inclusion of the full DSM amount is consistent with legislation. It will be for the Board to decide whether the proposed settlement complies with legislative provisions. From the perspective of the Consumer Advocate, the position expressed by NS Power represents a reasonable interpretation, based on all surrounding circumstances.
>
> [CA Closing Submission, p. 5]

[176] The Closing Submission filed by the Industrial Group and Dalhousie University similarly noted that "the Board will have to determine as a matter of statutory interpretation what was intended by the words 'increase respecting DSM'" noting that "Bill 212 is not a model of legislative clarity on this."

[177] The Board must, therefore, embark on its own analysis of the meaning of s. 64A(3) of the *PUA*, considering the text, context and purpose as discussed in *Vavilov*.

Text

[178] This analysis begins with the text of the provision:

> **64A (3)** For the purpose of Board Case Number M10431, the net rate increase for the utility, across all rate classes, in 2022, 2023 and 2024 must not be greater than one and eight-tenths per cent, with the exception of an increase respecting
>
> (a) fuel and purchased power; and
>
> (b) demand-side management approved by the Board.

[179] Reading through the provision, the Board notes that the word "utility" is defined in s. 64A(1) to mean "Nova Scotia Power Incorporated" and the application of the provision is limited to the current Board proceeding (M10431). The direction that is

provided is that “the net rate increase for the utility, across all rate classes, in 2022, 2023 and 2024 must not be greater than one and eight-tenths per cent.” The Board understands this to mean that it is not authorized to approve an overall average rate increase which results in more than a 1.8% increase in the overall average rates presently paid by ratepayers currently to the end of 2024 (aside from the exceptions considered in the following paragraphs of this decision). Because of differences in rate class cost-allocation and rate design, changes in rates in some rate classes may be more or less than the 1.8% cap, but the overall average (across all rate classes) must not be more than 1.8%.

[180] If there is any disagreement about whether the permitted 1.8% rate increase may occur in one year or must be spread evenly over the test years, there is no basis for it in the text of the provision. The text includes no restrictions on when the 1.8% increase might occur, beyond the requirement that the net increase in 2022, 2023 and 2024 be not more than 1.8%.

[181] The major dispute arises with the introduction of exceptions to the 1.8% rate increase cap for “fuel and purchased power” and “demand side management approved by the Board.” Increases “respecting” these matters may cause the net rate increase for the Utility to be more than 1.8%.

[182] The use of the word “respecting” suggests that the increase that is referenced is the previously mentioned “net rate increase” and not an increase in the cost of the excluded items specifically. Had the latter been intended, the use of the word “in” rather than “respecting” would have more clearly focused the question on an increase in approved costs for DSM.

[183] As discussed earlier, while rates and costs are related under cost of service rate regulation, they are not the same. A utility's costs are used to determine its revenue requirement, which is the amount of revenue the utility requires and that rates will be designed and set to recover. But once rates are set, actual costs will vary between rate cases, whereas rates will not. Rates remain the same until the next general rate application when the utility's costs will again be reviewed and used to determine a new revenue requirement to set new rates. Furthermore, rate changes may occur in a general rate application due to changes in demand, even if costs stay the same.

[184] The focus of the provision on rate increases rather than cost increases favours NS Power's interpretation of the provision but the words used are not "precise and unequivocal." Even if they appeared to be so, the words of a provision might be read differently in the fuller context of the legislation and when the legislative purpose is considered.

Context

[185] Considering the entirety of s. 64A, the Board observes that subsection (3) is included with other subsections that restrict NS Power's ability to seek rate increases or fully recover its costs. Some of these provisions were specific to earlier proceedings and time periods and have no current application. Subsections (2A) and (2C) fall into this category.

[186] Subsection 64A(2) restricts the Board's ability to grant a general rate increase sooner than 24 months after the effective date of the last increase; however,

64A(2B) confirms the Board's authority to order a staged or multi-year general rate increase.

[187] Subsection 64A(3A) was added by the *PUA* amendments along with s. 64A(3). It relates specifically to subsection (3) and directs that any net rate increase up to 1.8% must be kept separate from other funds of the utility and may only be used to improve the reliability of service to ratepayers (excluding increases respecting fuel and purchased power and demand side management approved by the Board).

[188] Subsections 64A(4)–(6) also refer specifically to s. 64A(3). Although the Board's starting assumption must be that the legislation is presumed to be accurate and well drafted, in this case the Board is forced to conclude that these subsections were either retained in error or that the Legislature made a mistake in fully repealing and replacing s.64A(3). Before Bill 212, s. 64A(3) read:

> **64A (3)** Subsection (2) does not apply if the Board determines that exceptional circumstances exist that have caused or will cause substantial financial harm to the ratepayers of the utility or to the utility.

[189] As mentioned previously, s. 64A(2) restricts the granting of a general rate increase to no sooner than 24 months after the last general rate increase. Before Bill 212, the Board could grant a general rate increase sooner if there were exceptional circumstances and if these circumstances had or would cause substantial harm to ratepayers or the utility. Subsections 64A(4) to (6) related to the authority of the Board to act in exceptional circumstances and required the Board to hold a hearing before determining whether exceptional circumstances existed and to hold a separate hearing on general rates only after it had determined that to be the case. As the Board's ability to act in exceptional circumstances appears to have been removed by Bill 212, the Board

cannot interpret subsections 64A(4) – (6) as having ongoing meaning and has ignored them in its contextual analysis of s. 64A(3).

[190] In the context of the surrounding sections of the *PUA*, the provision in question follows s. 64, which addresses a public utility's duty to obtain Board approval for its rates, tolls and charges. In different ways, s. 64A limits or qualifies the Utility's ability to seek rates or the Board's ability to approve them. It is followed by other provisions added by Bill 212 dealing with the return on equity in this proceeding and, beyond this proceeding, the payment of interest and the duty to return excess earnings to ratepayers.

[191] The provisions added by Bill 212 also target non-fuel costs, with a particular but not exclusive focus on NS Power's cost of capital and an exclusion for DSM costs. These Bill 212 amendments are grouped around a pre-existing limitation on the recovery of executive compensation.

[192] Collectively, these provisions appear to act as limits or exceptions to the general provisions in the *PUA* governing a utility's entitlement to the recovery of its costs through rates set by the Board. In particular, the recovery of proper allowances for depreciation in s. 41 and a just and reasonable return on rate base, reasonable and prudent expenses and all just allowances under s. 45. These other provisions in the *PUA* do not specifically address the interpretive differences over s. 64A(3) arising in this proceeding, but they do frame that provision as a limitation or qualification on the underlying right of a utility to recover its expenses based on the cost of service methodology that is the foundation of the *PUA*.

Purpose

[193] There are no explicit purpose provisions in the *PUA*. As discussed previously, the *Contracts Case* considered there were two great objectives enshrined in the *PUA* and almost all provisions in the statute are directed towards securing these two objectives:

(1) All rates charged must be just, reasonable and sufficient and not discriminatory or preferential.

(2) Service must be adequately, efficiently and reasonably supplied to the public.

[194] Regarding rates, the Appeal Division said they must be reasonable and just for the public served and sufficient for the utility. The rates must be sufficient to provide the utility with the opportunity to earn a just and reasonable return after allowing for operating expenses and other just allowances – no less and no more.

[195] The *Contracts Case* was decided in 1976. As just considered, s. 64A to 64C affect or qualify this general objective. These provisions were all added since 2006, 30 years after the *Contracts Case* and more than a decade after NS Power was privatized. Some of them, like s. 64A(3), were just introduced by Bill 212.

[196] Bill 212 also has no explicit purpose provision. NRR addressed the intent of the *PUA* amendments in its Closing Submission. It said that the 1.8% rate increase cap, which applied except for increases relating to fuel and purchased power and demand side management as approved by the Board, was a “reasonable and necessary step to reduce the inflationary burden facing Nova Scotians in the near-term.”

[197] NRR also said:

> 43. Bill 212 was introduced to protect ratepayers from significant shock based on unprecedented global inflationary pressures, as confirmed in the Premier's letter to the Board dated November 28, 2022. The terms of the Settlement Agreement increase rates and contravene the purpose, spirit, and intent of Bill 212.
>
> 44. Prior to the GRA proceeding, NSP returned a minimum of $125 million in profits each year for the last 12 years. These profits benefit NSP's shareholders but offer no direct benefit to ratepayers. NSP's original position in the GRA proceeding, if granted, would have further inflated these profits.
>
> 45. During harsh economic times, it is unreasonable to impose further hardship on ratepayers to enhance corporate returns. Corporate social responsibility calls for a sharing of the burden to maximize relief for ratepayers for the cost of an essential service.
>
> [NRR Closing Submission, p. 9]

[198] More directly, the Premier's letter stated: "The entire purpose of Bill 212 was to protect Nova Scotians."

[199] For the most part, the submissions the Board received from the other parties did not explicitly address the purpose of Bill 212. In the Reply Submission filed by the MEUs, they described what "the Province sought to do with the *PUA* amendments" as keeping the non-fuel costs in NS Power's rates as low as reasonably possible on behalf of ratepayers and providing options to contain NS Power's costs given the current affordability crisis facing Nova Scotians.

[200] The Board accepts that the Legislature passed Bill 212 with ratepayer protection in mind. However, s. 64A does not freeze rates. Furthermore, by explicitly excluding rate increases respecting fuel and purchased power, which by the time Bill 212 was introduced were clearly putting the most upward pressure on NS Power's rates, it does not prohibit large rate increases in this proceeding either. Instead, the protection appears to be aimed at a subset of NS Power's costs – non-fuel costs – with several

provisions aimed more specifically at NS Power's cost of capital (ss. 30(5), 64AA, 64AB and 64C).

[201] In terms of the exemption for DSM costs, the Board notes that while these are non-fuel costs, they are costs that are collected by NS Power to fund programs administered by EfficiencyOne. Under s. 79I of the *PUA*, NS Power must undertake cost-effective DSM by entering into a Board approved DSM purchase agreement with the DSM franchise holder that includes the amount that NS Power must pay the franchise holder to supply DSM.

[202] Section 79M(5) of the *PUA* directs the Board to provide for NS Power's recovery of costs it incurs under an approved DSM purchase agreement:

> **79M** (5) In making an order approving an agreement pursuant to Section 79L, the Board shall include a provision to permit Nova Scotia Power Incorporated to recover any costs Nova Scotia Power Incorporated incurs pursuant to the approved agreement, including through its rate base, pursuant to Section 45, in the year in which the costs are incurred or as deferred by the Board.

[203] The recovery of costs for DSM programs by NS Power is not for the purpose of directly funding its operations, although they are intended to provide ratepayer and system benefits. The funds are for the DSM franchise holders and the funding levels are specifically approved by the Board. The amount of spending is not in NS Power's control. Given the foregoing, DSM costs are different in nature from NS Power's other non-fuel costs which may be more prone to over-estimation, over-recovery and to lead to excess earnings.

[204] In summary, the Board must interpret the words of the legislation in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the *Act*, the object of the *Act*, and the intention of the Legislature.

[205] As discussed in the *Contracts Case*, one of the foundational principles underpinning the *PUA* is the “justness of rates,” which requires that rates must be sufficient to allow for the recovery of operating expenses and a “just and reasonable” return. Bill 212 affects the Board’s ability to set rates based on these principles in this proceeding.

[206] The Legislature enacted the *PUA* amendments to protect ratepayers. Although s. 64A(3) can be viewed as establishing a form of rate cap, it did not preclude increases in rates. Given the exclusion of fuel and purchased power costs when these were expected to cause significant upward pressure on rates, it also did not preclude large increases in rates. Instead, the protection afforded by the *PUA* amendments appears to be focused on NS Power’s non-fuel costs, with several amendments targeting NS Power’s cost of capital and earnings.

[207] NS Power and NRR disagree about the interpretation of s. 64A(3)(b). NS Power submitted that the permitted rate increase respecting demand side management approved by the Board is to be determined based on the amount of DSM costs included in the revenue requirement used when rates were last set in the *2013-2014 GRA* decision (which was nothing). NRR submitted that the permitted rate increase respecting DSM may only include the incremental increase in costs between approved DSM spending in 2022 and the test years. Reading s. 64A(3) harmoniously with the scheme of the *Act*, the object of the *Act* and the intention of the Legislature, the Board finds that NS Power’s interpretation is more compelling (and by extension that of the parties to the GRA Settlement Agreement who urged the Board to accept it).

[208] The text of s. 64A(3) addresses rate increases. Although NS Power has clearly used revenue collected from ratepayers to pay for DSM costs since its last rate case, the base (or general) rates set at that time did not include DSM costs. As such, all of NS Power's DSM costs in its revenue requirement for 2023 would be incremental to the revenue requirement used to set 2014 rates (NS Power's current rates).

[209] This interpretation best respects the underlying principles of the *PUA* as expressed in the *Contracts Case* and the specific requirement in s. 79M(5) permitting NS Power to recover DSM costs. At the same time, it does not defeat the objective of Bill 212. Although Bill 212 is intended to protect ratepayers, the exclusion of fuel costs, which were exerting the most pressure on rates, suggests the intent was to limit a type of cost rather than to limit potentially large increases.

[210] The focus of Bill 212 is on non-fuel costs, especially, although not exclusively, those affecting NS Power's cost of capital and earnings. The exclusion of DSM costs is consistent with this, since although they are collected by NS Power, they are provided to EfficiencyOne to fund its Board-approved programs. As such, these revenues are less likely to contribute to NS Power's earnings, particularly given ratepayer requests to true-up these costs since 2015. With the approval of the DSM Rider sought by NS Power in this proceeding, which is generally supported by NRR, that possibility is virtually eliminated.

[211] Based on the interpretation of s. 64A(3) of the *PUA* on which the rates under the GRA Settlement Agreement are proposed, ratepayers receive meaningful benefits consistent with the types of costs targeted by Bill 212. Rate increases in respect of non-fuel items are nearly half of what they were proposed to be before Bill 212. Much of this

is achieved through reductions in NS Power's earnings, compared to what it had originally requested.

7.3.4 Findings

[212] The *PUA* requires the Board to set fair rates for utilities. As discussed in the *Contracts Case* considered earlier in this decision, that means rates that are fair as between the utility and its customers, and as between the utility's various customer classes. Fair rates as between the utility and its customers are rates that provide the utility with an opportunity to earn a just and reasonable return after providing for the recovery of reasonable and prudent operating costs and other just allowances. The fair return requirement is discussed in more detail later in this decision.

[213] The Board is satisfied on the evidence in this proceeding that the proposed rates under the GRA Settlement Agreement are appropriate. The Board finds that the proposal is within what is permitted under the *PUA* (including Bill 212). The Board is also satisfied that NS Power's reasonable and prudent costs will be at least as much as the effective revenue requirement needed to support the proposed rates.

[214] While NS Power has noted that the "non-fuel, non-DSM cap" imposed by Bill 212 will reduce its forecast revenue increase by $70 million over 2023 and 2024, the Board agrees with the submissions filed by the Industrial Group and Dalhousie University, and by the MEUs, that cost reductions can be achieved, and that they must be achieved without sacrificing reliability.

[215] While the Board has concluded that NS Power's reasonable and prudent costs support the increases under the GRA Settlement Agreement, it is rarely the case

that rate increases are welcomed by customers. In this case, the back-to-back 6.9% increases in 2023 and 2024 are concerning, particularly in a period of higher inflation.

[216] For many, electricity rates are already unaffordable. This was certainly the sentiment expressed by many Nova Scotians who took the time to prepare and send letters of comment to the Board about this application. This concern was also aptly stated in the Affordable Energy Coalition's Opening Statement and Closing Submissions:

> Nova Scotia has one of the highest rates of energy poverty in the country due to our lower incomes and higher energy costs arising from our reliance on oil and coal. Energy services are necessities – for food preparation, winter warmth and as the planet heats up, for summer cooling. Access to energy is a human rights issue. Access is often threatened due to low incomes. Many families struggle with the "heat or eat" challenge especially in this period of high fossil fuel prices.
>
> [Exhibit N-105, Opening Statement, p. 2 and Closing Submissions, p. 2]

[217] As noted by the Nova Scotia Court of Appeal in *Dalhousie Legal Aid Service*, the Board's regulatory power under the *PUA* is not an instrument of social policy. The Board cannot, as noted by the Federal Court of Appeal in *TransCanada Pipelines Ltd. v. Canada (National Energy Board)*, 2004 FCA 149, simply disallow NS Power's reasonable costs to make rates more affordable (discussed in more detail later in this decision). While the Board can disallow costs found to be imprudent or unreasonable (and has), absent such a finding, NS Power's costs must be reflected in the rates paid by customers.

[218] That said, there are regulatory tools available to the Board to mitigate the impact of rate increases. For example, the Board may defer the recovery of costs to a later period, or it may direct the creation of a regulatory asset to be amortized over an extended period rather than be recovered all at once. This is the premise underpinning the proposed Decarbonization Deferral Account in this proceeding. It would be a means of managing the significant costs expected to be incurred by electricity ratepayers to

transition away from coal-fired electricity generation and have 80% of electricity in the province supplied by renewable energy by 2030 and towards the Province's net-zero GHG emissions target by 2050.

[219] There are trades-offs involved with using these tools. Requiring future ratepayers to pay the costs of current customers can create concerns about intergenerational equity. Additionally, the delayed recovery of legitimate costs generally attracts interest or similar carrying costs, which increases the overall amount paid by ratepayers. This was the essence of NRR's comments in its Closing Submissions where it said, "Deferrals can mitigate rate shock to consumers in the short term, but over time the total amount payable is increased because of interest chargeable to ratepayers for financing the deferral."

[220] In this regard, the Board observes that the anticipated fuel costs in 2023 and 2024 (as well as unrecovered fuel costs to the end of 2022) are already partially excluded from the base fuel costs for 2023 and 2024 under the GRA Settlement Agreement. If these costs are incurred as forecast, the result is essentially a deferral of a significant amount of fuel costs. These costs are proposed to be included in FAM Riders in 2024 and 2025, although "as the rate increase required to collect under-recovered fuel amounts in a 2024 FAM Rider is material for all or certain of the customer classes, the parties will work in a good faith manner to defer a portion of the impact of the increase and costs to 2025 or an additional period as may be reasonable and appropriate."

[221] In the GRA Settlement Agreement, a balance was struck between NS Power and representatives of all its customer classes. It included the Affordable Energy

Coalition, which works on behalf of low- and modest-income Nova Scotians across the province. It also included the Ecology Action Centre.

[222] Given the broad acceptance by customer representatives and these other parties, and the looming cost pressures likely to arise through the energy transition, the Board finds the proposed rate increases in the GRA Settlement Agreement to be just and it would not be appropriate in this case to defer even more fuel costs for additional and temporary rate relief in the test years. In addition to the intergenerational equity and higher cost concerns noted above, this runs the very real risk of compounding rate pressures from the energy transition in the future and reducing the flexibility that may be available to manage those costs in a reasonable timeframe.

[223] Finally, the Board notes that it has received many comments from the public about NS Power's requested rate increase in the face of concerns about reliability. In its *NS Power 2005 GRA* decision, the Board stated:

> 16 …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]

The Board continues to be of this view.

7.4 Cost of Capital and Earnings Sharing

[224] NS Power's current rates are set on a return on equity (ROE) of 9% and a capital structure consisting of 37.5% equity. The Utility's actual annual returns may produce an ROE as high as 9.25% with equity forming as much as 40% of its capital structure. NS Power must return earnings above these thresholds to its customers.

[225] The Utility's obligation to return earnings above its approved limits was first established under a settlement agreement in 2007. Since that time, excess earnings have benefited ratepayers through various mechanisms. When the Section 21 tax deferral existed, excess earnings were used to reduce that deferral. In recent years, excess earnings were applied directly to balances owing by ratepayers through the FAM. In its decision on NS Power's 2020-2022 Fuel Stability Plan [2019 NSUARB 165], the Board confirmed its jurisdiction to determine the disposition of excess earnings, regardless of whether NS Power agreed to it in a settlement with other parties.

[226] In this proceeding, NS Power proposed to continue to set rates based on a 9% ROE, but to permit actual returns within a range up to 9.5%. NS Power also requested that the Board approve changes to its debt-to-equity ratio, for rate setting purposes, starting in 2022 at 61.2%/38.8% and then increasing the equity component to 41.3% in 2023, followed by an increase to 43.8% in 2024. Additionally, NS Power asked for

permission to earn on a common equity thickness of up to 45% in each year between 2022 and 2024. NS Power proposed that any surplus earnings above these thresholds be shared equally by NS Power and its customers.

7.4.1 The Fair Return Requirement and Standard

[227] NS Power has a natural monopoly as there is limited competition and the forces of supply and demand in the electricity market are absent in Nova Scotia. Part of regulating NS Power includes determining the rate of return that is used in setting customers' rates. As discussed earlier, s. 45 of the *PUA* entitles a utility to earn a just and reasonable return on its rate base, in addition to the recovery of its operating expenses and other just allowances.

[228] A fair return on rate base is important for the sustainability of NS Power's service. A low return on rate base may discourage investment in the Utility. It may also lead to a poor credit rating, which will cause financial institutions to increase the rate of interest on loans 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.

[229] There is a well-recognized and long-standing legal standard the Board must follow when approving a utility's return on its investment. Nearly 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. <u>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.</u> In fixing this net return the Board should take into

> consideration the rate of interest which the company is obliged to pay upon its bonds as a result of having to sell them at a time when the rate of interest payable thereon exceeded that payable on bonds issued at the time of the hearing. To properly fix a fair return the Board must necessarily be informed of the rate of return which money would yield in other fields of investment. Having gone into the matter fully in 1922, and having fixed 10% as a fair return under the conditions then existing, all the Board needed to know, in order to fix a proper return in 1927, was whether or not the conditions of the money market had altered, and, if so, in what direction, and to what extent. [Emphasis added]
>
> [*Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] S.C.R. 186]

[230] 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.).

[231] 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 <u>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.</u> 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]

[232] The Federal Court of Appeal went on to address 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 its 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 this consideration 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.

[233] The Board notes 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).

[234] Similar principles are considered by utility regulators in the United States: *Bluefield Waterworks & Improvements Co. v. Public Service Commission of West Virginia* (1923), 262 U.S. 679 (U.S. W. Va.) and *Federal Power Commission v. Hope Natural Gas Co.* (1944), 320 U.S. 591 (U.S. Sup. Ct.).

[235] In *Energy Law and Policy* (Kaiser and Heggie, ed., 2011), Canadian authors, Gordon Kaiser and Bob Heggie, summarized the principles that have been 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]

[236] *Northwestern Utilities*, *Bluefield* and *Hope* were recently referenced by the Board as the "landmark decisions which set out general principles with respect to rate of return" in *Re Nova Scotia Power Inc.*, [2019 NSUARB 165, para. 119].

[237] The assessment of these principles in any case before the Board is based on the evidence presented. In the current case, the Board was presented with expert evidence by several parties.

7.4.2 Overview of Cost of Capital Evidence

[238] NS Power presented evidence from its cost of capital expert witness James Coyne, of Concentric Energy Advisors, who used a combination of Discounted Cash Flow (DCF) models, the Capital Asset Pricing model (CAPM) and an Alternative Risk Premium model. Mr. Coyne estimated a ROE for NS Power of 10.1% based on the average of his model analysis. However, NS Power did not seek to increase its ROE for rate setting purposes from 9.0 %.

[239] Mr. Coyne suggested that increasing NS Power's common equity ratio from 37.5% to 45% is justified as NS Power faces greater financial and business risk. This assessment of greater financial risk is based on his comparison of common equity ratios of other utilities, finding NS Power's to be lower than the 40.4% average of Canadian utilities. He also compared NS Power's credit metrics to groups of selected comparator utilities and concluded that NS Power's credit metrics are weaker than comparable U.S. electric utilities. Mr. Coyne also deemed that NS Power faces considerable business risk

because of its ownership of thermal generation assets, weak economic conditions in Nova Scotia, weather and risk posed by regulation. He identified NS Power's obligation to decarbonize its electricity generation is fast approaching, which will require considerable investment. Mr. Coyne also suggested that NS Power has higher regulatory risk than other comparable utilities in his selected proxy groups due to the Fuel Adjustment Mechanism and the potential for expenditure requests to be denied.

[240] The cost of capital expert witness for Board Counsel, Dr. Laurence Booth recommended a 7.5% ROE based on his financial modeling using the CAPM and DCF models and his informed assessment of the market risk premium. He considers 7.5% reasonable for NS Power because it is no riskier than other electric distribution utilities in Canada which have a significantly lower average risk than U.S. utilities.

[241] Dr. Booth recommended that NS Power keep its common equity ratio at 37.5% as its business risk has not changed since the previous GRA. Rather, he considers that since 2012, NS Power improved its business risk assessment with S&P Global to "excellent" (before the introduction of Bill 212). In his evidence, Dr. Booth noted that NS Power has been able to earn its allowed ROE in most years since the previous GRA, which he sees as proof that it does not face long run risk. Further, Dr. Booth viewed money market conditions as positive, noting that after 2022, GDP growth is forecasted to be two percent with optimal employment levels. Regarding inflation, he suggested that the main forces of inflation in 2022 are the impact of COVID-19 and Russia's invasion of Ukraine, which have caused supply shortages and a significant increase in commodity prices. He cited forecasts by the Royal Bank of Canada in May and June 2022 and the

Bank of Canada itself expecting these inflationary factors to ease in 2022/23 and return to targeted levels.

[242] The CA's cost of capital expert witness, Dr. Randall Woolridge, noted that the current average authorized ROE for a Canadian utility is 8.83%, below the average authorized ROE in the U.S. of 9.38%. Based on his financial modeling using the CAPM, DCF and Risk Premium models, he recommended an ROE for NS Power of 8.75% with an earnings band of 8.5% to 9.0%. Dr. Woolridge acknowledged that this rate is slightly below the average for electric distribution companies, but that it reflects the low levels of interest rates and cost of capital.

[243] Dr. Woolridge recommended keeping NS Power's common equity ratio at 37.5%. He considered that NS Power's BBB+ credit rating with S&P Global was in keeping with other electric utilities and indicated that its risk is similar to other electric utilities (before the introduction of Bill 212). Additionally, Dr. Woolridge considered that NS Power demonstrated consistent financial performance under its current common equity ratio which earned it a strong credit rating. The Board notes that the S&P credit rating referenced by Dr. Woolridge was downgraded two notches since the passage of Bill 212.

[244] Dr. Woolridge noted that Mr. Coyne's model assumes higher interest rates and higher costs of accessing capital; however, he disagreed and considered that, from a historical perspective, interest rates and cost of capital in both Canada the U.S. are still low. In his view, utilities have taken advantage of the low interest rates of recent years. In his evidence he noted that starting in 2022, interest rates have increased in response to an improving economy and high levels of inflation. Although the central bank increased

interest rates, those increases reflect short-term lending rates, whereas long-term rates reflect expectations of economic growth and inflation. Dr. Woolridge cited U.S. investors' expected inflation using the inflation-protected Treasuries (TIPS) for the next five years at just above three percent, while the 10 and 30 year expected inflation rates are forecast below three percent. He noted that the current environment is reflective of a bond-market inversion, where short-term inflation expectations are higher than long-term inflation rate expectations. Dr. Woolridge concluded that interest rates and cost of capital are still at low levels while stock prices are high. Reported inflation is the primary economic concern; however, he viewed the outlook for the economy as positive in the long-term based on the TIPS expectations.

[245] Paul Chernick and John Wilson of Resource Insight, on behalf of the CA, made two recommendations about NS Power's requested change to its capital structure. First, they requested that the Board consider NS Power's refusal to communicate with the Board about delays and cost overruns on projects. Second, they asked that the Board consider NS Power's repeated capital cost overruns when setting the ROE.

[246] John Dalton of Power Advisory, NRR's expert witness, considered that NS Power's business risks were overstated by Mr. Coyne, citing the rating by S&P Global as "excellent" and its competitive position as "excellent", (note that these ratings have changed since the passage of Bill 212). Mr. Dalton suggested that Mr. Coyne did not account for the mitigating effects of the proposed DDA and the FAM on risk. He said NS Power's sales from residential and commercial customers are less affected by the business cycle, which mitigated commercial risk. Mr. Dalton noted that competition from

other fuel providers in the province is limited, insulating NS Power from competitive market forces.

[247] Mr. Dalton reasoned that Mr. Coyne misinterpreted Nova Scotia's economic position and demographic changes. Forecasts of economic growth in Nova Scotia from other sources are more favorable than the single source selected by Mr. Coyne. Mr. Dalton countered the weak demographic projections with recent population growth figures for 2021 from Statistics Canada.

[248] John Athas and Melissa Whitten of Daymark, on behalf of the SBA, recommended that NS Power should maintain its current ROE for rate setting purposes and its current range for actual earnings. They considered that applying the approved ROE to a higher equity thickness is equivalent to increasing the Utility's WACC by the difference in expected to actual equity thickness, and then providing the Utility with a bonus ROE.

[249] Daymark recommended that the Board deny NS Power's request to increase its common equity ratio to 45% and asked that it not be allowed to use an equity thickness higher than its actual equity thickness in any year. Daymark considered that investment in utilities is more attractive during periods of high inflation which reduces NS Power's investment risk. Further, NS Power's application did not suggest that it cannot access low-cost debt.

[250] Albert Dominie on behalf of the MEUs did not recommend a specific debt-to-equity ratio or ROE, but he asked that the Board consider the magnitude of the cost implications of NS Power's request to increase its common equity and thresholds for its ROE on customers over the long-term.

7.4.3 *Public Utilities Act* Amendments

[251] As discussed already, the recent amendments to the *PUA* affected the Board's discretion in this proceeding when setting NS Power's rate of return on equity and capital structure. Under s. 64AA, NS Power's return on equity must not be set at a rate greater than 9.25% and its equity ratio must not be greater than 40%. Under s. 64C, NS Power must return earnings above its approved range for return on equity to ratepayers. Although this continues the practice that has been in place for approximately 15 years, it is now mandatory under the legislation.

[252] Some Intervenors noted that the recent *PUA* amendments altered what they planned to ask the Board to set for the cost of capital for NS Power in this proceeding. As noted earlier in this decision, the Affordable Energy Coalition noted that they had argued in their Opening Statement that NS Power's profit level should be reduced but they signed the GRA Settlement Agreement "in view of the disruption created by Bill 212 and its effect on NSPI's financing." In their view, Bill 212 undermined the independent regulation of the electricity system and resulted in the downgrading of NS Power's credit rating and that this disruption "undermined our ability to argue for reduced profit levels at this time." It intends to pursue that issue in future proceedings.

[253] Counsel for the Industrial Group and Dalhousie University advised:

> The parties have agreed in the Settlement Agreement to an equity thickness of 40% and ROE of 9% for rate-setting, with an earnings band +/- 25 basis points. While our submissions had been drafted to argue for no change in NSPI's equity thickness and ROE, the basis for this draft argument was shaken in the wake of the PUA amendments and more recent bond and credit rating reports which speak to NSPI's current credit risk profile.
>
> It is challenging to know what weight should be placed upon these hearsay third-party reports and how they would be accounted for in standard utility risk assessment methodologies. Given the timing of the PUA amendments, none of the cost of capital experts has provided evidence on their impact to NSPI's risk premium. The assessment is complicated in light of the inter-relationship between NSPI and Emera.

> At present, Dalhousie University and the Industrial Group simply observe that the hearing evidence of a predictable and stable regulatory environment has been undermined. Approval of the Settlement Agreement offers some counter-balancing de-risking mechanisms: an increased equity thickness, agreement in principle on a DDA, a time-limited storm cost recovery rider, a DSM rider, continued pass-through of fuel costs and it leaves open the door for NSPI to apply for other cost deferrals. It is anticipated that DBRS Morningstar will be considering these and other matters before its next credit report is issued.
>
> [IG/Dalhousie Closing Submissions, p. 5]

[254] The CA commented specifically about the rate of return on equity:

> The Settlement Agreement seeks to set the return on equity at 9%. It is to be noted that both the Consumer Advocate and Board counsel consultant evidence supported a lower return on equity than 9%. Prior to the introduction of Bill 212 it had been the intention of the Consumer Advocate to seek a return on equity at less than 9%. That position was to be – in large measure – rooted in the opinions of Dr. Booth and Dr. Woolridge that the robust and independent rate setting process in Nova Scotia should lead to a lower return on equity. The passage of Bill 212 represented a post-hearing development that materially altered what reasonable position could be taken regarding the return on equity. In all those circumstances the Consumer Advocate submits that the Settlement Agreement ROE figure of 9% is reasonable.
>
> [CA Closing Submission, p. 4]

[255] The recent *PUA* amendments do raise serious questions about the continuing reliability of the opinions expressed by the cost of capital experts who presented the Board with evidence in this proceeding. As noted by Kaiser and Heggie, the comparable investment principle considers the return available in the market on an investment of similar risk.

[256] Bill 212 certainly had an impact on bond rating agency assessments of NS Power's risk. In response to information requests after filing the GRA Settlement Agreement with the Board, NS Power filed recent reports from DBRS Morningstar and S&P Global discussing this issue [Exhibits N-156 (IR-10) and N-159].

[257] In a report dated October 20, 2022, DBRS noted its "business risk assessment of NSPI will be negatively affected by the proposed amendment as the heightened and adverse political interference will reduce the predictability and stability of

the regulatory framework." On December 20, 2022, DBRS downgraded its "Issuer Rating and Unsecured Debentures & Medium-Term Notes rating [for NS Power] to BBB (high) from A (low) and its Commercial Paper rating to R-2 (high) from R-1 (low)."

[258] In a report dated October 24, 2022, S&P said it viewed the "amendment as negative for credit quality because it would likely weaken Emera Inc.'s financial measures and increase business risk, reflecting heightened regulatory risk." S&P went on to note:

> If the proposed legislation is passed, it would override Nova Scotia's robust regulatory process. Under our base case, we expect that utilities operate under a regulatory system that is sufficiently insulated from political intervention to efficiently protect the utility's credit risk profile even during stressful events. As such, Emera faces heightened regulatory risk in the province of Nova Scotia, supporting a potential reassessment of the regulatory framework in Nova Scotia, which could pressure credit quality.
>
> [Exhibit N-156, NSUARB IR-10, Attachment 2, p. 2]

[259] On November 21, 2022, S&P downgraded its long-term issuer credit rating on NS Power and its issuer-level rating on its senior unsecured debt by two notches to 'BBB-' from 'BBB+'. It also lowered its Canadian scale commercial paper rating on the company to 'A-3 (Cdn)' from 'A-1(Low)'. In doing so, S&P cited "political intervention that will materially undermine the NSUARB's regulatory construct and significantly increase NSPI's stand-alone business risk."

[260] As counsel for the Industrial Group and Dalhousie University highlighted, the legislation and bond rating agency reaction post-dated the filing of evidence by the cost of capital experts who appeared in the proceeding and the oral hearing, where the parties and the Board had an opportunity to question these experts about their opinions. It is possible, if not likely, that the passage of legislation like Bill 212 would have influenced the opinions about the risks faced by NS Power expressed by the experts in this proceeding. It is difficult to know the precise impact these events would have had on the expert opinions presented to the Board in this proceeding, but the events are fundamental

enough that the Board must question whether it can put any weight on the expert evidence it has received.

[261] Still, despite this difficulty, the Board must approve a cost of capital for NS Power in this application. The expert evidence filed in this proceeding conflicted. The approaches, assumptions and conclusions of each cost of capital expert were critiqued and challenged to such a degree that, in the Board's assessment, there is hardly any part of the cost of capital analysis that would not require the Board to make a finding in favour of one expert or another following a step-by-step review of their criticisms.

[262] Considering the Board's doubt about the weight to be put on this evidence after Bill 212, it would not be productive to engage in a point-by-point analysis of the cost of capital evidence. Instead, recognizing that there is enough variability in the cost of capital analysis (even absent Bill 212) that the results should be considered as a range of reasonable outcomes rather than a single and precise data point, the Board will consider whether the proposed return on equity and capital structure under the GRA Settlement Agreement are reasonable in the circumstances.

7.4.4 Return on Equity

[263] Under the GRA Settlement Agreement, the parties agreed to an ROE of 9% for rate setting purposes, within a range of 8.75% to 9.25%. This maintains the status quo. For rate setting purposes, it is lower than the maximum rate of return on equity allowed under s. 64AA(a) of the *PUA*.

[264] NS Power relies on the evidence it presented through the course of this proceeding to support the proposed rate of return on equity under the GRA Settlement

Agreement. The Company maintains that the evidence of its cost of capital expert witness, Mr. Coyne of Concentric Energy Advisors, justifies an even higher rate of return.

[265] As discussed already, cost of capital experts, Dr. Woolridge and Dr. Booth, filed evidence expressing their opinions that the rate of return on equity should be lower. Dr. Woolridge recommended an 8.75% ROE, while Dr. Booth's opinion was it should be 7.5%. Based on this evidence, it was open to the Board to conclude that NS Power's return on equity should be lowered, but in the circumstances, the Board finds the ROE proposed in the GRA Settlement Agreement is reasonable.

[266] In reaching this conclusion, the Board notes that although there was a more significant gap between Dr. Woolridge's recommended ROE and Mr. Coyne's, compared to the ROE proposed by NS Power, Dr. Wooldridge's recommendation is at the bottom of NS Power's existing approved range and only 25 basis points lower than the current rate of return, which is proposed to be maintained under the GRA Settlement Agreement. Further, with just one adjustment open to the Board to make on the evidence in the proceeding, Dr. Woolridge's opinion would be higher than the current rate of return.

[267] Dr. Woolridge did not apply any adjustment to his analysis for costs associated with securing equity (flotation costs). While Dr. Woolridge submitted such an adjustment was not appropriate because NS Power did not incur these costs, both Mr. Coyne and Dr. Booth adjusted their recommendations to allow for flotation costs. At the hearing, Dr. Booth explained his reasons for doing so:

> …the basic principle is simply that the equity cost is the market equity cost, what Mr. Coyne said was the secondary market, that is what investments require. So that is the building block for all of us.
>
> But in order to sell shares to the capital market, you incur flotation costs. You incur some costs. So we used to have huge litigation on this. At one point, the Régie asked Gaz Metro to go back and track all of its equity issues for almost forever and say what were the actual

> costs because the Régie took the requirement to a fair and reasonable return on actual costs literally, and they allow less than 1.5 basic points.
>
> Utility witnesses have come in and they've said they want 125, 150 basis points.
>
> So across Canada, we've sort of come to a consensus that 50 basis points was fine. That basically means the utility can earn 50 basis points more than the equity cost and the stock price will sell just a little bit above its book value. And as a result, there's no dilution of the equity value and the equity holders are treated fairly.
>
> So do I agree with 50 basis points? All I know and I agree with is we did that, and we haven't had any litigation or evidence on that, I'd say, for at least 10 to 12 years.
>
> [Transcript, September 16, 2022, pp. 1554-1556]

[268] It is a bit more difficult to reconcile Dr. Booth's overall recommendation on the appropriate rate of return on equity for NS Power with the GRA Settlement Agreement. But the Board notes that much of the criticism leveled by Dr. Booth against the opinions expressed by Mr. Coyne (and indeed, by Dr. Woolridge) was based on their reliance on market data for United States utilities and his opinion of the comparability of market evidence in Canada and the United States. In his view, return expectations in the United States are higher and cannot be applied in a commensurate manner in Canada. In his evidence, Dr. Booth said, "US financial markets exhibit more risk than the Canadian markets and have generated higher risk premia in the past."

[269] Dr. Booth's evidence includes a comparison of market risk premium estimates in Canada and the United States, but he also references two reports by Moody's. Dr. Booth commented on a passage from the second report, in 2009, in his evidence:

> Further in discussing the US and Canada Moody's stated:
>
> > "Moody's views the regulatory risk of US utilities as being higher in most cases than that of utilities located in some other developed countries, including Japan, Australia and Canada. The difference in risk reflects our view that individual state regulation is less predictable than national regulation; a highly fragmented market in the US results in stronger competition in wholesale power markets; US fuel and power markets are more volatile; there is a low likelihood of extraordinary political action to

> support a failing company in the US; holding company structures limit regulatory oversight; and overlapping and unclear regulatory jurisdictions characterize the US market. As a result no US utilities, except for transmission companies subject to federal regulation, score higher than a single A in this factor."

> Moody's went on to discuss how 4 of the 6 investor-owned bankruptcies in the US resulted from regulatory disputes culminating in insufficient or delayed rate relief for the recovery of costs and/or capital investment in utility plant. Moody's further stated, "as is characteristic of the US, the ability to recover costs and earn returns is less certain and subject to public and sometimes political scrutiny." I would emphasise here Moody's phrase "as is characteristic of the US" since this reflects how legal principles are implemented rather than differences in those principles. This phrase betrays an underlying cultural attitude towards risk that is different from Canada. I am aware that since then, Moody's has reappraised some of the effects of state regulation in the U.S and given greater weight to secured financing but the U.S is still a different country with different values.

> [Exhibit N-52, pp. 102-103]

[270] Dr. Booth elaborated on these comments in his testimony at the hearing. It was likely this evidence was in mind when the Industrial Group and Dalhousie University said in their Closing Submissions "that the hearing evidence of a predictable and stable regulatory environment has been undermined" by the recent *PUA* amendments. Whether Bill 212 would influence Dr. Booth's overall assessment of risk is unclear; however, the Board considers that the mitigation of risk through regulation in Canada was a foundational element of his opinion.

7.4.5 Capital Structure

[271] Under the GRA Settlement Agreement, the parties agreed to an equity thickness of 40% for rate setting purposes, with earnings in any given year determined on an actual five-quarter average equity thickness of up to 40%. This exceeds the 37.5% currently used for rate setting purposes, although the 40% maximum equity thickness is what is currently allowed when determining actual annual earnings. It is also the maximum equity thickness under s. 64AA(b) of the *PUA*.

[272] As noted, NS Power proposed to increase its equity thickness to 45% for rate setting purposes. However, it proposed to phase this in over the test period so that rates would be set based on 38.8% equity in 2022, 41.3% in 2023 and 43.8% in 2024. In all years, NS Power proposed that its actual earnings be permitted to be determined on an equity ratio of up to 45%. As discussed above, NS Power relied on Mr. Coyne's evidence, which recommended a 45% equity thickness. Dr. Woolridge and Dr. Booth both recommended that NS Power's equity thickness for rate setting purposes be maintained at 37.5%.

[273] In its application, NS Power also said that although it proposed to phase in its requested increase in equity thickness, "the 45 percent common equity ratio put forward in the Coyne Evidence represents the minimum equity ratio NS Power forecasts as being required to maintain its current credit metrics over the 2022-2024 rate stability period." NS Power advised that, at its current rates, its cash flow-to-debt (or funds from operations) metrics would be below the levels required by DBRS and S&P to maintain its credit ratings.

[274] Dr. Woolridge questioned NS Power's assessment of its needed credit metrics to maintain its credit ratings. With reference to a June 10, 2022, S&P report [Exhibit N-127], Dr. Woolridge said S&P projected funds from operations-to-debt to be in line with a BBB+ rating. Although the report cites a base case assumption that NS Power's rates are consistent with what it proposed in its general rate application, Dr. Woolridge suggested S&P would have expected that NS Power would not have gotten everything it was asking for in its application.

[275] In response to questions from the Board at the hearing, Dr. Booth advised that the Board should be concerned about NS Power's credit metrics, but he noted they were not the only measure that bond rating agencies consider. He also cautioned that this was a "bond market problem", not an "equity market problem." He said there were other solutions to getting the bond rating up, such as issuing preferred shares.

[276] Since the hearing, and following the introduction and passage of Bill 212, NS Power's credit rating was downgraded by both DBRS and S&P. In its November 21, 2022, report, S&P said it expected NS Power's funds from operations-to-debt to be between 10% and 12% through to 2025 [Exhibit N-156, Attachment 3, p. 3]. In its December 20, 2022, report, DBRS stated:

> … While DBRS Morningstar is encouraged by the Company and the intervenors filing a negotiated settlement for the GRA, DBRS Morningstar expects NSPI's earnings and key credit metrics to be moderately weaker over the near term but to be supportive of the BBB (high) ratings. DBRS Morningstar notes that NSPI will need to find operational efficiencies and has committed to focus its planned capital expenditures (capex) on only reliability and safety projects in order to preserve its key credit metrics. NSPI's parent company, Emera Inc., has also historically been supportive of the Company by maintaining a flexible dividend payout policy and providing equity injections to maintain the debt-to-capital ratio within regulatory parameters. As such, DBRS Morningstar does not consider further negative rating actions on NSPI to be likely at this time unless there is additional political intervention in the ratemaking process that results in even higher volatility and uncertainty for the Company or leads to key credit metrics that are no longer in line with the BBB rating category. A positive rating action may occur if DBRS Morningstar sees (1) the regulatory process for the next GRA conducted free of any interference and with the NSUARB's full independence on the determination of rates, (2) meaningful progress on the replacement of coal-fired plants with renewable sources in order to meet the mandated targets, and (3) key credit metrics return to be in line with the "A" rating category.
>
> [Exhibit N-159, p. 1]

[277] In its Closing Submission, NS Power continued to rely on Mr. Coyne's evidence to support the smaller increase in equity thickness to 40% and said Bill 212 was further justification for approving the increase for rate setting purposes:

> In NS Power's view, all of this taken together, along with the overall record of this proceeding, provide the justification for the 40 percent common equity ratio included in the Settlement Agreement. However, the PUA Amendments serve to reinforce this justification as NS Power just now also operate within the constraints imposed by the PUA

> Amendments and deal with the financial implications arising from the PUA Amendments' impact on NS Power's credit ratings.
>
> [NS Power Closing Submission, p. 19]

[278] From the closing submissions filed by Intervenors who were parties to the GRA Settlement Agreement, it is clear they felt it necessary to respond to the credit rating agency response to Bill 212 by agreeing to an increase in equity thickness for rate setting purposes. NRR was the only Intervenor to expressly oppose this proposal. It questioned why Intervenors would agree to a 40% equity thickness when Dr. Booth and Dr. Woolridge recommended staying at 37.5% and submitted the Board should maintain this level based on that evidence. It submitted any increase would only increase profits to NS Power without any direct benefit to ratepayers and said if the Board determined that an increase in equity thickness was warranted, it must not exceed the 40% maximum under the *PUA* amendments.

[279] In its Reply Submission, NS Power took issue with NRR's characterization of the increase in its equity thickness as providing no direct benefit to ratepayers and with its recommendation to the Board to maintain the 37.5% equity thickness for rate setting purposes:

> The NRR submission, at paragraph 32, characterizes NS Power's approved return on equity as a return to investors "for which ratepayers receive no direct benefit." This is not correct. NS Power's Board-approved return on equity represents the just and reasonable cost NS Power pays to those who invest capital in the Company, allowing it to make the investments necessary to continue to provide safe and reliable service on behalf of customers. This cost of capital therefore provides a direct benefit to customers. Without revenue sufficient to pay the costs to obtain this capital, NS Power is not able to make such investments.
>
> …
>
> NRR's position that NS Power's current "37.5% ratio remains reasonable and should be maintained" ignores the PUA Amendments and the adverse impacts they have had, and will continue to have, for NS Power and its customers. These impacts are severe and will be long lasting. They have materially altered the assumptions and understandings used and held by the experts who provided cost of capital and capital structure evidence in this

> proceeding. This has been recognized and acknowledged by nearly every participant in this proceeding, but for NRR.
>
> [NS Power Reply Submission, pp. 9-11]

[280] Bill 212 has clearly had an impact on bond rating agencies. That is a concern to the Board as it should be to all ratepayers, and is undoubtedly why the proposal to increase NS Power's equity thickness was supported by representatives from all customer classes and the Affordable Energy Coalition which, while advocating on behalf of low-income customers, noted that a stable, appropriately financed electricity system is in the interest of every customer, including low-income customers, to ensure reliability, the achievement of environmental goals and affordability.

[281] The Board also notes that, given the choice between addressing changes in business risk by adjusting the rate of return on equity or the capital structure, Dr. Booth preferred adjustments to the capital structure:

> With a choice between capital structure versus ROE adjustments; my preference is to adjust for business risk in the capital structure for two main reasons. First, the market seems to consider any changes in the allowed capital structure to be a more permanent change, while it expects the ROE to change with capital market conditions. Since business risk is the primary determinant of capital structure, it is to be expected that a regulator will change an allowed capital structure relatively infrequently in response to significant changes in business risk. Second, allowing firms to choose their capital structure and then adjusting the ROE to a fair return runs the risk that although the equity holders are getting a fair rate of return, the overall utility income and thus rates, are too high and unfair. An extreme example here would be a regulated firm that "chooses" 100% equity financing. The regulator might then give a fair ROE, but rates are still unfair and unreasonable since the company is forgoing the tax advantages of using debt financing.
>
> One corollary to the decision of many regulators such as the CER, the BCUC and AUC to adjust capital structures in response to business risk differences is that the risk faced by shareholders in Canadian utilities is very similar. This is the very essence of why the AUC and BCUC, for example, have generic hearings on the ROE: to a great extent they have reduced differences in business risk by allowing the use of deferral accounts and altering equity ratios.
>
> [Exhibit N-52, pp. 10-11]

7.4.6 Excess Earnings

[282] In keeping with the requirement to return excess earnings to customers under s. 64C of the *PUA*, NS Power withdrew its request for a revised earnings sharing mechanism.

7.4.7 Findings

[283] Overall, the Board finds the proposed rate of return on equity under the GRA Settlement Agreement to be reasonable in the circumstances. The GRA Settlement Agreement maintains the status quo. Intervenors representing most of NS Power's customer classes supported the GRA Settlement Agreement as did the Ecology Action Centre and the Affordable Energy Coalition. No Intervenor opposed this aspect of the GRA Settlement Agreement, including NRR, who submitted "that the existing approved range of earnings should be maintained" in its Closing Submissions.

[284] The proposed rate of return is lower than the rate warranted according to Mr. Coyne and comparable to the rate recommended by Dr. Woolridge (in fact lower if a flotation adjustment is added to Dr. Woolridge's recommendation). Dr. Booth's evidence could support a lower rate of return on equity. However, given the foregoing and the Board's concerns about whether he would maintain his recommendations after Bill 212, the Board does not believe it should give Dr. Booth's evidence more weight than the other factors favouring the Board's approval of the proposed rate of return on equity in the GRA Settlement Agreement.

[285] The Board also concludes that the proposal in the GRA Settlement Agreement to increase equity thickness to 40% for rate setting purposes is reasonable.

There is no change to recovery on actual equity thickness, which is currently authorized at up to 40%. Further, while a higher equity thickness is assumed for rate setting purposes, the Board is satisfied that rates under the GRA Settlement Agreement will be based on an effective revenue requirement that is lower than it otherwise would have been in the absence of Bill 212.

[286] Additionally, the increased equity thickness for rate setting purposes received broad support from Intervenors in this proceeding, with the only party specifically opposing it being NRR. There was evidence before the Board which suggests the equity thickness should be even higher. The Board also considers that the downgrading of NS Power's credit rating must be addressed, as it poses a real risk to achieving electricity prices at the lowest long-term cost. It also impacts NS Power's ability to attract capital investment and to participate in the debt financing markets.

[287] The ROE and capital structure proposed in the GRA Settlement Agreement and approved in this decision are within the limits set in S. 64AA of the *PUA*. Any actual earnings realized by NS Power above the thresholds approved in this decision must be returned to ratepayers under s. 64C of the *PUA*. The current requirement to return any such funds through the FAM will continue, subject to the consideration of any future request by NS Power or ratepayers to refund overearnings to ratepayers through a different mechanism, including the decarbonization deferral account that may be established.

7.5 Decarbonization Deferral Account

[288] NS Power's application included a proposal to implement a DDA. In general terms, the DDA was proposed as a rate stability tool to consolidate the actual costs of the Company's transformation to 80% renewable electricity and phase out its coal-fired generating plants by 2030, and to facilitate the subsequent recovery of those costs in a transparent manner to promote rate stability and affordability for customers. Specifically, the DDA proposed in NS Power's application allowed for the following:

- Depreciation expense for coal-fired assets and associated marine unloading and fuel delivery infrastructure facilities recovered through rates for the 2022-2024 GRA is proposed to be calculated in accordance with the depreciation rates currently approved, regardless of when these assets are actually retired;

- Additional amortization of the unrecovered capital investment and decommissioning costs is proposed to be incurred to reflect full recovery of the thermal assets by their expected retirement date to allow for compliance with legislative requirements;

- The additional amortization expense is proposed to be accumulated in the DDA regulatory asset, resulting in a movement of the unrecovered amounts from plant-in-service to a regulatory asset;

- Other prudently incurred costs incremental (or decremental) to the amount included in NS Power's revenue requirement associated with the Company's obligation to meet the legislative requirements would also be included in the DDA. As discussed previously, these items would include both direct and indirect costs associated with the transition to more clean energy and may include depreciation expense and financing costs on assets to support the transition to clean energy, additional decommissioning expense incurred on thermal assets, incremental operating and maintenance expense, employee transition costs, and write-off of materials and fuel inventory for thermal generating facilities that are no longer required, and termination costs associated with fuel supply contracts;

- The DDA regulatory asset is proposed to be recovered over future periods. The amount of proposed recovery in future periods will take into account affordability for customers and timely recovery of the costs and will be subject to NSUARB approval; and

- The DDA regulatory asset is proposed to be included in rate base as the balance accumulates.

[Exhibit N-16, pp. 49-50]

[289] With respect to the early retirement of NS Power's thermal assets by 2030, NS Power indicated that the DDA would serve as a regulatory asset that effectively eliminates the requirement for a depreciation study for these assets. The Company noted

that reclassifying the unrecovered costs of these assets from plant-in-service to an approved regulatory asset would allow for increased flexibility in the timing of recovery of these costs to the benefit of NS Power's customers and the Utility as the costs would no longer need to be depreciated over the remaining useful life of the assets. Instead, these costs could be recovered over an appropriate timeline in the future, which would be intended to best balance customer affordability with the timely recovery of the costs.

[290] The Intervenors expressed varied opinions about the DDA proposed in NS Power's application. Board Counsel consultant, Grant Thornton, noted that the DDA provides a reasonable mechanism to capture additional amortization of unrecovered thermal asset capital investment and decommissioning costs by the expected retirement dates. They also stated that the DDA gives NS Power and the Board flexibility in the timing of the recovery and allows NS Power to not propose recovery of these costs through accelerated depreciation in revenue requirement in this GRA. However, Grant Thornton was not able to support NS Power's position on the direct and indirect costs element of the DDA, believing that more information is needed around the costs to be incurred.

[291] Daymark recommended that the DDA should not include accelerated depreciation due to anticipated early retirement; however, it should be used to recover undepreciated balances of early retired generation after retirement occurs. They also suggested that the eligibility of DDA investments should be established as part of ACE proceedings, and that costs that are normally expensed should be prohibited from being incorporated into a DDA. Further, Daymark noted that the DDA may be helpful to demonstrate a lower risk regulatory environment in Nova Scotia.

[292] Melissa Whited, Board Counsel consultant, stated that the DDA, as proposed in the application, is not reasonable, as its scope extends far beyond accelerated retirement costs. She recommended that the DDA be rejected, and that NS Power instead address the costs associated with early retirement of thermal assets through its existing Accounting Policy 6350. This policy states that in order to enhance rate stability, where a write off is significant and Board approval is obtained, the undepreciated cost of the asset should be amortized, on a straight-line basis, over five years or over a reasonable period, subject to Board approval. The unamortized cost may remain in rate base, and any cost of capital should be expensed in the period incurred.

[293] Resource Insight agreed with NS Power that regulatory assets, including deferral accounts and other similar accounting mechanisms, can reasonably be used to address retirements and unusual investments. However, Resource Insight was concerned that almost any future capital costs could be associated with the transition to clean energy and eligible for inclusion in the DDA. They opined that this would eliminate the linkage between established practices for determining depreciation rates. Therefore, similar to Ms. Whited, they recommended that NS Power's proposal to include costs associated with early retirements, including uncollected decommissioning costs, in the DDA be rejected. They believe there is no compelling reason to develop entirely new accounting policies to handle the amortization costs associated with early retirements. They did not object to the Board considering revisions to Accounting Policy 6350 to allow for amortization of regulatory assets to extend longer than five years. Resource Insight also recommended that indirect costs and savings associated with Eastern Clean Energy Initiative (ECEI) capital project costs should be excluded from the DDA or any other

authorized deferral account. Further, they recommended that NS Power establish a capital tracker deferral accounting mechanism (which could be named DDA) for the four ECEI projects.

[294] Mark Drazen, on behalf of the Industrial Group and Dalhousie University, stated that NS Power's application for approval of the DDA involves a rather open-ended approach to the costs that might be transferred to the account. He, therefore, recommended that the Board reserve judgment on the DDA until the Board and ratepayer stakeholders can study potential effects.

[295] With respect to the treatment of early retirement of NS Power's thermal assets, Christine Runge, of behalf of NRR, opined that the question left to the Board in this proceeding is essentially one of rate shock and the associated strategy to mitigate the impacts. She stated that the Board must determine to what extent the bill impacts are a concern and if there is adequate value from the mitigation of bill impacts to justify the higher total costs to customers. Ms. Runge recognized that the DDA could potentially be the best option for recovery of costs associated with the early retirement of thermal generation assets. However, her evidence noted that this could not be confirmed based on the information provided on the record of this proceeding. As such, she recommended that the Board not approve nor reject the DDA until NS Power files the following information so that the proposed DDA can be more thoroughly evaluated:

- a new depreciation study, the associated rates required to collect the costs in that manner, and the bill impacts of this approach;
- the amounts by generator that are expected to remain undepreciated on the forecast date of retirement, the annual rate impact of collecting those costs over five-year periods under Accounting Policy 6350, and the bill impacts of this approach; and

- a forecast of the dollar value of the DDA at the time collection begins, guidance on the amortization period that may be required, the increase in total costs paid by consumers from this alternative, and the bill impacts of this approach.

[296] With regards to the inclusion of future generation assets in the DDA, including the recovery of direct and indirect costs associated with the transition to clean energy, Ms. Runge stated that such costs are all business-as-usual costs that NS Power should be able to manage under its Cost of Service (COS framework). She, therefore, recommended that this element of the proposed DDA be rejected by the Board.

[297] Under the terms of the GRA Settlement Agreement, the signatory parties have agreed, in principle, to a DDA to recover NS Power's undepreciated thermal asset Net Book Value (NBV) and unrecovered decommissioning costs. They have also agreed to engage constructively in a consultative process to confirm the practice and procedures that will be followed to establish the DDA and its scope, to affect the transfer of unrecovered costs to a regulatory asset and to recover such costs. This process will result in NS Power providing a report to the Board describing the results of the consultative process and seeking approval of the DDA by June 30, 2023. For greater certainty, the GRA Settlement Agreement confirms that the Board's decision in [2012 NSUARB 133] with respect to the MEUs responsibility for the payment of stranded costs continues to apply and is not affected by the DDA agreement in principle. The parties have also agreed to discuss the potential for the application, approval, and implementation of the DDA, or similar mechanism, as it relates to "New Capital Assets" and "Incremental/Decremental OM&G costs", as those are described in Section 4.1 of NS Power's Rebuttal Evidence (i.e., energy transition investment and related costs).

7.5.1 Findings

[298] In the Board's view, it is important to note that the DDA, as presented in NS Power's application, was proposed by the Company in the context of the requirement to retire a significant amount of thermal assets, as provincial and federal policymakers desire transformative change to reduce carbon and emissions on an accelerated timeline:

> A significant part of the transition will require the retirement of a large amount of thermal generating stations fueled by coal and other fossil fuels. For regulated utilities, their investments in thermal assets were made to serve customers under what is known as the Regulatory Compact…For these assets, which face the need for cost recovery beyond traditional depreciation levels due to the Energy Transition, significant work is being undertaken by utilities and regulators to determine the form and timing of their cost recovery, and how to optimize their value in the interim. Well-established regulatory principles require that utilities be provided the opportunity to recover prudently-incurred costs, even if such assets should become subsequently under-utilized or retired earlier than previously expected, especially when the cause of those outcomes is a change in legislation or regulatory policy. The Energy Transition is creating the need to shift away from the use of thermal assets, and to confront the retirement of assets where such actions are necessary to meet environmental mandates for carbon reduction or otherwise provide net savings to customers.
>
> [Exhibit N-17, Appendix 7A, p. 10 of 72]

[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.

[300] This notwithstanding, in its Closing Submission, NRR submitted that NS Power's request for approval of a DDA should be denied. In support of this submission, NRR argued that the mechanics of the DDA remain unclear, and there are other existing mechanisms available to NS Power that it can use to address depreciation concerns. In particular, while NRR did acknowledge that a DDA could potentially be a useful tool, NRR contends that NS Power did not present sufficient information to assess the DDA's utility relative to other options.

[301] With respect to the use of a DDA to address the early retirement of NS Power's thermal assets, as proposed in the GRA Settlement Agreement, the Board disagrees with NRR's contention that it should be denied.

[302] First, the GRA Settlement Agreement is not proposing approval of the DDA at this time. It is clear that the GRA Settlement Agreement represents only an agreement in principle among the signatories with regard to a DDA for accelerated depreciation costs associated with NS Power's undepreciated thermal asset NBV and unrecovered decommissioning costs. An application for approval of such a DDA has yet to come before the Board. Further, the specifics of how the DDA will work are proposed to be developed in a stakeholder consultation process. This process will result in NS Power providing a report to the Board describing the results of the consultative process and seeking Board approval of the DDA by June 30, 2023.

[303] In addition, in response to NRR GRA Settlement Agreement IR-11(c), NS Power confirmed that the GRA Settlement Agreement rates for 2023 and 2024 do not include any costs related to the DDA. As such, the Board finds that the DDA will not impact 2023 and 2024 rates proposed in the GRA Settlement Agreement.

[304] The Board agrees with NRR and other Intervenors that there are other options available to NS Power to address recovery of costs associated with the early retirement of the Company's thermal assets. Nevertheless, based on the proposed GRA Settlement Agreement, the Board must address whether a DDA provides an appropriate means to recover these costs. The Board finds that it does for the reasons described as follows.

[305] First, as confirmed during the hearing, NS Power's ability to recover costs associated with early retirement of thermal capital assets does not vary between a scenario in which the DDA is approved and the current means of cost recovery:

> **Q.** (Murphy)…in your rebuttal evidence on page 27, lines 9 to 12, when you refer to retirement of the coal plants, you note that:
>
> > Financing costs associated with these thermal assets are included in revenue requirement and embedded in proposed rates. When the unrecovered amounts associated with these assets are moved to the DDA account, [Nova Scotia] Power proposes to continue expensing these costs and there will be no financing costs associated with these assets deferred and added to the DDA.
>
> …So is this -- specifically, does this mean that there will be no increase in overall financing costs because the transfer to the DDA in fact won't result in a change to rate base and it won't change any depreciation expenses associated with those assets? I think that's what you were saying yesterday, but I just want to make sure.
>
> **A.** (Flemming) Yes, that is correct.
>
> **Q.** Okay. That was a long way of getting to an answer, but thank you.
>
> So can you confirm that once a coal plant is retired and it's no longer in property, plant, and equipment, can you confirm that the amount for that particular asset that's in the DDA will be amortized at current depreciation rates until the DDA amortization period is set?
>
> **A.** (Flemming) Yes, that's correct. We're proposing to keep -- well, to redirect funds that would have previously been to depreciate the cost of property, plant, and equipment to amortization of the DDA as to not decrease Nova Scotia Power's revenue requirement as a result of moving these assets to the DDA.
>
> [Transcript, September 14, 2022, pp. 654-656]

In effect, upon retirement of these assets, the depreciation expense in rates would be directed to amortization of the DDA regulatory asset, until such time that a DDA amortization period is set by the Board.

[306] Further, the Board has regulatory tools to manage rate impacts on customers when the recovery of capital assets over a period does not match the underlying life of an asset. With the DDA, until the amortization period is set, there will be no rate impacts. Moreover, any future rate impacts can be addressed in separate proceedings with customers where the Board will have flexibility to manage rate impacts and affordability. As noted by Mr. Reed in his evidence:

> As it is currently conceived, approval and implementation of the DDA would not bring any immediate rate impacts. The DDA is designed for the transferring and tracking of decarbonization-related costs into a single account. A subsequent regulatory proceeding would need to be initiated, an amortization period established, cost allocations and rate impacts determined, and Board approval received, before rate impacts would flow through to customers.
>
> [Exhibit N-17, Appendix 7A, p. 25 of 72]

[307] The Board also finds that a DDA to recover costs associated with early retirement of thermal capital assets offers superior benefits to other cost recovery mechanisms available to NS Power, particularly Accounting Policy 6350. Specifically, addressing these retirements under Accounting Policy 6350 would result in numerous deferral accounts with varying impacts to revenue requirement and potentially different amortization terms. This issue was discussed extensively during the hearing:

> **Q.** (MacDonald) So I recognize from evidence heard today and yesterday, that under -- I believe if we were to see these assets depreciate individually, or amortize, rather, as individual assets, that we may see multiple potential amortization accounts – amortization deferral accounts. Is that correct?
>
> **A.** (Flemming) Yes, that's absolutely correct. As Mr. Reed spoke to earlier, the current process with accounting policy 6350, if we were to retire these assets and amortize them, as the policy is currently written, you would have a separate amortization, a separate amortization account for each of these retiring assets. They would be fixed in nature and, you know, that's, I think, a drawback to the current practice that we have of application of the 6350, setting the amortization period. It's not as flexible as the proposed DDA, and

really, it doesn't acknowledge the fact that we're looking at a whole system transformation, as Mr. Ferguson spoke to earlier.

Q. I take it, though, that this individual amortization deferral accounts would be scrutinized as individual accounts as opposed to the -- as I believe the panel and maybe Mr. Reed refer to it as yesterday -- the pot. Is that correct?

…

A. (Flemming) It accumulates all the costs in one -- in one account. And so instead of having, as Mr. Reed spoke to, 10, 11 different amortization accounts, and then maybe you need flexibility and you don't have just 10 or 11 decisions, now you have 40, 50, upwards decisions. So we think that that is a key -- that looking at it on the holistic and acknowledging the total power system transformation is a key benefit.

However, the scrutiny associated with the remaining asset balances, the scrutiny with any balance that gets added to the DDA, we would expect and anticipate that there will be full Board review and full transparency of any of these balances.

[Transcript, September 13, 2022, pp. 415-418]

[308] The extent of individual deferral account requirements under Accounting Policy 6350 would result in excessive regulatory burden and costs. In contrast, the DDA mechanism consolidates the balances associated with these unrecovered capital assets, is holistic in nature and is simple to administer.

[309] NRR has argued that deferral mechanisms, such as the DDA, can mitigate rate shock to consumers in the short term, but over time the total amount payable is increased because of interest chargeable to ratepayers for financing the deferral. The Board notes, however, that use of Accounting Policy 6350 would also result in such cost deferrals and related financing charges. In the Board's view, the flexibility inherent in the DDA, as compared to Accounting Policy 6350, allows for simpler adjustments to amortization and revenue requirements that better balance timely recovery of costs and affordability for customers while considering other cost pressures facing NS Power and customers. Finally, as noted by the CA:

…the establishment of a thermal asset DDA provides a single gathering place for the significant cost associated with the early retirement of the thermal assets. The early retirement of the thermal assets was mandated by various levels of government. The

> thermal asset DDA will provide transparency regarding the substantial costs faced by Nova Scotia ratepayers as a result of government-imposed asset retirements.
>
> [CA Closing Submission, pp. 3-4]

[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.

[311] The Board, therefore, approves a DDA in principle to recover NS Power's undepreciated thermal asset NBV and unrecovered decommissioning costs. This approval is subject to stakeholders engaging in a consultative process to confirm the practice and procedures that will be followed to establish the DDA and its scope, to effect the transfer of unrecovered costs to a regulatory asset and to recover such costs.

[312] To be clear, the Board is not approving a formal DDA at this time. Instead, the Board will wait for a report submission by NS Power describing the results of the stakeholder consultative process. The Board will only consider approval of implementation of a DDA after submission of that report and a formal application for approval by NS Power.

[313] The Board also confirms that its decision in [2012 NSUARB 133] with respect to the MEUs responsibility for the payment of stranded costs continues to apply and is not affected by the Board approval of the DDA agreement in principle.

[314] Notwithstanding the Board's approval of the DDA in principle to recover costs associated with early retirement of thermal capital assets, the Board agrees with the Industrial Group and Dalhousie University that all matters surrounding the DDA remain open for discussion with stakeholders, including the future possibility of securitization as an alternative to financing at WACC. As such, the Board believes it would be useful at this stage to identify some of the items it believes need to be addressed through a DDA stakeholder consultative process. These issues include, but are not limited to:

- Assets to be included in the DDA;
- Timing of transfers to the DDA;
- Unrecovered plant balances at the time of transfer to the DDA;
- Rationale for selection of future amortization periods;
- Appropriate rate of return on the DDA;
- Potential use of securitization;
- Tracking of sustaining capital costs per plant until retirement;
- Continuity schedule per plant;
- Annual DDA reporting requirements; and
- Identification of expected and unrecovered decommissioning costs, as offset by COR and ARO.

[315] NS Power is no longer seeking Board approval of a DDA mechanism to recover other energy transition related costs. Nevertheless, the parties to the GRA Settlement Agreement have agreed to discuss this issue further. Specifically, the GRA Settlement Agreement includes a provision to continue stakeholder discussion about the potential application, approval, and implementation of a DDA or a similar mechanism as it relates to incremental or decremental revenue requirements associated with the ECEI projects; and direct costs (OM&G and depreciation expense) and indirect costs (financing and income tax) associated with the transition to clean energy that are not included in the Company's revenue requirement. This provision of the GRA Settlement Agreement

provides an opportunity to discuss potential DDA terms and conditions during stakeholder consultation and address any related concerns of stakeholders and the Board. The Board approves of stakeholders proceeding with this consultation.

7.6 Storm Rider and Climate Change Adaptation Plan

[316] NS Power's application includes OM&G costs for storm restoration in its revenue requirements. NS Power proposed a base rate allowance for Level 1/Level 2 storm restoration OM&G costs and a base rate allowance for Level 3/Level 4 storm restoration OM&G costs. NS Power classifies storms as follows:

- Level 1 – Regional Service Restoration Response: less than 50,000 customers affected, and restoration expected to be completed within 12 hours.
- Level 2 – Multi-Region Service Restoration Response: less than 50,000 customers affected, and restoration expected to be completed within 36 hours, or more than 50,000 customers affected but restoration expected to be completed within 24 hours.
- Level 3 – Provincial Service Restoration Response: less than 50,000 customers affected, and restoration expected to require more than 36 hours, or more than 50,000 customers affected but restoration expected to be completed within 72 hours.
- Level 4 – Corporate Service Restoration Response: more than 50,000 customers affected, and restoration expected to require more than 72 hours.

[317] In its application, NS Power proposed the following base rate allowances for storm restoration OM&G costs:

($ millions)	**Level 1 and 2 Storm Costs**	**Level 3 and 4 Storm Costs**
2022	$7.3	$10.5
2023	$7.2	$10.2
2024	$7.3	$10.4

[318] The 2022 forecast was determined by taking the average storm restoration OM&G expense from 2016 to 2020 and removing the Post-tropical Storm Dorian extreme

storm event. This amount was then escalated for inflation and adjusted for forecast savings due to the implementation of AMI technology. NS Power's exclusion of the impact of Post-tropical Storm Dorian is due to the Company's proposed Storm Rider (to be discussed in the following sections). Absent approval of the proposed Storm Rider, NS Power's budget for storm restoration expense was proposed to increase by $3.5 million each year.

[319] The Company noted that Level 3 and 4 storm events and the associated costs for timely customer outage restorations are becoming more substantial and largely beyond the ability of the Utility to predict precisely or control. NS Power stated that this circumstance exists across the industry and is becoming more challenging with the impacts from global climate change. Further, the Company noted that its 2014 OM&G storm restoration expense included in the 2013-2014 GRA compliance filing was $10.8 million, while its storm restoration expense has exceeded that level in each year from 2016 to 2020.

[320] The occurrence of one or more extreme storm events within a year could result in actual storm restoration OM&G expense that is significantly higher than the amount included in NS Power's revenue requirement. To avoid including estimated costs for such extreme events in base rates, NS Power has proposed a storm restoration deferral and recovery mechanism (Storm Rider) for approval as part of this GRA. The requested Storm Rider would apply to storm restoration OM&G costs exceeding those included in the Level 3/Level 4 storm costs forecast in any given year. It would not apply to costs exceeding Level 1/Level 2 forecast storm costs.

[321] The proposed Storm Rider has the following key elements:

- The Level 3 and Level 4 storm costs forecast, determined in the manner described above, will be included in the revenue requirement and base rates.

- Actual Level 3 and Level 4 storm costs will be tracked throughout the year and, at the end of the first quarter of each year, the prior year actual costs will be determined and compared to the amount included in customer rates.

- If the actual results exceed the amount included in the revenue requirement, the Company, at its discretion, will apply to the Board for a charge (the Storm Rider) to be applied to recover the shortfall effective January 1 of the following year. The Company will endeavour to make this application by April 30.

- All non-capital preparation, response, and restoration related costs associated with Level 3 and Level 4 storms will be eligible for inclusion in the Storm Rider, including (1) storm preparedness including crew staging and related logistical expenses; (2) incremental NSPI wages, benefits, and overtime pay related to storm recovery; (3) costs of external service providers and mutual aid utilities hired by the Company during restoration efforts; (4) materials and supplies used to repair damaged assets and any associated expenses; and (5) other recoverable expenses, including extra costs for temporary repairs and to expedite the permanent repair of damaged property and expenses incurred for providing services to customers whose electric service has been interrupted.

- Eligible storm costs to be included in the Storm Rider in any given year cannot exceed 2 percent of that year's forecast retail revenues of the Company. Any eligible storm costs in excess of the 2 percent cap will be deferred to the subsequent year's Storm Rider.

- The initial costs included in the Storm Rider for a specific year are based on annual actual results, and so will not change once they are determined. Actual volumes billed to customers, however, may vary from projections, leading to over- or under-recovery of storm costs. Any such over- or under-recoveries of the costs included in the Storm Rider will be determined at the end of each year and included in the calculation of the subsequent year's Storm Rider.

- The cost of financing the deferral will be calculated at NS Power's approved Weighted Average Cost of Capital and added to the deferral balance.

[Exhibit N-16, pp. 105-106]

[322] In response to an IR from NRR, NS Power explained its inclusion of Level 3/4 costs and exclusion of Level 1/2 costs in the proposed Storm Rider as follows:

> Figure 12-4 of the Application provides annual storm costs from 2016 to 2020 for Level 1 and Level 2 storms and Level 3 and Level 4 storms. The Level 1 and Level 2 storm costs range from $4.8 million to $9.5 million. The Level 3 and Level 4 storm costs are significantly more variable and material, ranging from $6.4 million to $22.3 million annually. While all storms are outside of the utility's control, it is the volatility, the materiality and difficulty in accurately forecasting the annual Level 3 and Level 4 storm costs that the Company is seeking to address through the proposed Storm Rider.
>
> [Exhibit N-40, Response to IR-20, p. 1]

[323] NS Power also proposed that Level 3/Level 4 storm restoration OM&G costs exceeding the Company's base rate Level 3/Level 4 cost allowance would be allocated to each rate class, consistent with the allocation of storm response costs in the cost of service. The Storm Rider rate would be applied based on projected sales (in kWh) by rate class. Further, the earliest a Storm Rider could take effect would be 2025 for 2023 costs.

[324] Concentric, on behalf of NS Power, indicated that the use of adjustment clauses (that operate through rate riders) and deferral and variance accounts has grown over time, and the use of such non-base rate mechanisms to track and recover costs is prevalent throughout the North American utility industry. Concentric noted that these types of cost recovery mechanisms tend to focus on the recovery of costs that are: (1) volatile and/or difficult to project, (2) potentially significant, and (3) generally outside of the utility's control. As such, since Level 3 and 4 storm restoration costs meet these criteria, Concentric argued that the associated OM&G costs are well suited for recovery through the proposed Storm Rider. Concentric also believes that the proposed Storm Rider is an appropriate mechanism to help address the challenges facing the Company over the coming decade, and is in line with industry precedent.

[325] For the most part, the Intervenors did not object to the imposition of the Storm Rider. In fact, Ms. Whited, on behalf of Board Counsel, noted that a rider can be

a reasonable method for recovering major storm costs that are outside the control of the utility. However, a number of parties took issue with the Storm Rider's asymmetric construct. They believe that the proposed Storm Rider is inequitable because actual Level 3 and 4 storm restoration OM&G costs over the base rate allowance are eligible for recovery, while there is no provision for a refund to customers if actual costs are below the base rate allowance. These parties recommended that the Storm Rider mechanism be adjusted to capture both cost under-recoveries and over-recoveries. Ms. Runge, on behalf of NRR, further recommended that the Storm Rider be adjusted to include Level 1, 2, 3 and 4 storm restoration OM&G costs. Daymark, on behalf of the SBA, suggested that the Storm Rider would be helpful to demonstrate a lower risk regulatory environment in Nova Scotia. Daymark also recommended that each Storm Rider application include a review of NS Power's preparation, storm response, the legitimacy of outages duration, and the prudency of system hardening planning.

[326] Under the terms of the GRA Settlement Agreement, the signatories have agreed to accept the imposition of the proposed Storm Rider only for the years 2023, 2024 and 2025 (for recovery, if applied for by NS Power, from 2025 to 2027). During this period, the signatories have agreed that the Storm Rider construct will be as per the Storm Rider Direct Evidence PR-01 page 106 and PR-01 Att1v, but, modified as per Section 13 of NS Power's Rebuttal Evidence, to eliminate the volume provision of the Balance Adjustment from the Storm Rider. The signatories have also agreed that NS Power will have the option to apply to the Board for recovery of costs through the Storm Rider if Level 3 and Level 4 storm restoration expenses exceed $10.2 million in 2023, $10.4

million in 2024, and $10.4 million in 2025. The GRA Settlement Agreement notes that the Storm Rider will terminate after recovery of costs from 2025.

7.6.1 Findings

[327] The issue of whether the forecast savings, due to the implementation of AMI technology, were properly applied by NS Power to its Level 1, 2, 3 and 4 storm restoration OM&G base rate allowances was discussed extensively during the hearing. In particular, a number of parties noted that NS Power may not have properly reflected anticipated 10% OM&G cost savings in the base rate allowances, as had been identified in the Company's original AMI application, approved by the Board (Matter M08349). Upon questioning by the Board, NS Power explained how it applied the projected savings. The Board accepts this explanation. Therefore, it finds that AMI savings have been properly applied to storm restoration OM&G base rate allowances.

[328] In its Closing Submission, NRR argued that the proposed Storm Rider, as presented in the GRA Settlement Agreement, is not necessary and is not in the best interests of ratepayers. One of NRR's primary concerns is about the asymmetric nature of the proposed rider, as expressed by several Intervenors. The Board too had concerns about the rider's asymmetric construct as presented in NS Power's original application. However, the Board finds that the GRA Settlement Agreement effectively lessens these concerns by providing a three-year trial period over which the Storm Rider's effectiveness, equity and whether it is, in fact, in the best interest of ratepayers, can be thoroughly tested.

[329] The Board also agrees with the Industrial Group's Closing Submission asserting that the recent *Public Utilities Act* amendments capping non-fuel rates at 1.8%

mitigates the concerns about the asymmetric design of the Storm Rider and reduces the risk of NS Power over-collecting storm restoration OM&G costs in base rates for this GRA.

[330] NRR also asserted that NS Power's proposed Storm Rider is reactive rather than proactive. NRR referenced the hearing testimony of Mr. Dane, where he referred to the Storm Protection Plan Cost Recovery Rider (SPPCRR) proactive storm recovery mechanism in Florida. However, as noted by NS Power in its Reply Submission, Florida utilities also use another storm restoration cost recovery mechanism similar to NS Power's proposed Storm Rider. This was confirmed by NRR's own expert witness, Mr. Dalton, where he noted in his evidence that Florida utilities have typically been allowed to recover storm restoration costs on a retrospective basis.

[331] In his Closing Submission, the CA stated:

> - Storm Rider - Unlike the Storm Rider applied for by Nova Scotia Power, the Settlement Agreement Storm Rider has a maximum term of 36 months. It is the view of the Consumer Advocate that a definitive time period effectively provides for a trial implementation of a Storm Rider. The trial period can be used to assess whether a Storm Rider (in a more permanent form) is in the best interest of rate payers. In addition, the trial Storm Rider provides an opportunity for an additional consideration and assessment of system reliability and service restoration times - which are essential concerns for residential ratepayers.
>
> [CA Closing Submission, p. 4]

[332] The Board agrees with this assessment, and approves the Storm Rider as described in the GRA Settlement Agreement. In addition, the Board directs NS Power to submit annual reports summarizing actual storm restoration costs for each year of the trial period. This reporting is to include a summary of actual Level 1, 2, 3 and 4 storm restoration costs. It shall indicate the monetary amount of any Level 1/2 and Level 3/4 cost underruns or overruns from base rate allowances. These annual reports shall be submitted by April 1 of each year in 2024, 2025 and 2026. At the end of the three-year trial period, the reports will be used to help assess the effectiveness and equity of the

Storm Rider, whether the Storm Rider remains in the best interest of ratepayers and whether adjustments to its construct are required.

[333] NRR stated that the GRA Settlement Agreement Storm Rider does not encourage NS Power to take reasonable efforts to harden its system or mitigate the storm restoration costs that will be passed along to ratepayers. NRR argued that instead, NS Power seeks to recover Storm Rider costs from ratepayers without any accountability for the reasonableness of NS Power's own mitigation efforts. NRR recommended that, should the Storm Rider be approved, any assessment of the reasonableness of costs incurred and subject to the Storm Rider should include an analysis of not only the prudency of costs for restoration, but also of the Company's efforts to harden the system and mitigate storm costs in advance of extreme weather events.

[334] The GRA Settlement Agreement appears to be silent on this issue. In addition, the Board finds that NS Power's Reply Submission is somewhat vague on the matter and suggests that such a review would be subject to only a prudency review of the Storm Rider costs. However, this issue was discussed extensively during the hearing. In particular, the following exchange occurred during questioning of NS Power by the CA:

> **Q.** (Mahody) In the event this storm adjustment mechanism or rider is approved as you've applied for it, as we come to that first hearing in 2024, and let's say -- and let's say there's an extra $2 million in costs all relating to Level 3 and 4 storms, the reality, though, is that there's the amount that's in rates for Level 3 and 4 if your application goes forward as applied for, and then you're talking about the incremental difference, say, of a couple million dollars.
>
> Do you agree with me that you need to -- it needs to be a full review of all Level 3 and 4 storm costs in order to be able to consider that incremental amount and the reasonableness and prudence of that incremental amount?
>
> **A.** (Ferguson) I do.
>
> [Transcript, September 20, 2022, pp. 1694-1695]

[335] Based on this exchange, it appears to the Board that NS Power partially agrees with the position taken by NRR. Further, as noted by Ms. Runge in her evidence:

> 83. It is also important to note that while the existence of a storm and the need to repair damaged assets is outside of the utility's control, the amount spent to repair those assets is within the utility's control.
>
> [Exhibit N-48, p. 25]

[336] The Board, therefore, finds it is appropriate for a review of a Storm Rider cost recovery application to include a full review of all Level 3 and 4 storm restoration costs for the applicable year, not just those Level 3 and 4 storm restoration OM&G costs that exceed base rate allowances.

[337] Moreover, the costs associated with NS Power's storm hardening and vegetation management efforts (beyond those associated with storm restoration) are also within the Company's control. The Board has no doubt that these efforts can have a direct impact on the magnitude of required storm restoration costs. Therefore, the Board agrees with NRR that a Storm Rider cost recovery review needs to assess not only all Level 3 and 4 storm restoration costs, but all costs expended by NS Power in the related year aimed at storm hardening, including vegetation management costs.

[338] Therefore, the Board finds that when NS Power submits a Storm Rider cost recovery application for Board approval, it is appropriate for the assessment of the application to include a full review of all storm restoration costs (including capital expenditures), storm hardening costs and vegetation management costs during the related year. The Board directs NS Power to include full detail on all these costs in each Storm Rider cost recovery application submitted during the three-year trial period. In advance of the first Storm Rider cost recovery application, the Board further directs NS

Power to engage with stakeholders to determine the specifics for how this information is to be presented.

[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 prudency 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.

[341] Finally, in its Closing Submission, NRR asserted that NS Power has been delinquent in its investments in system reliability, particularly related to vegetation management. NRR stated that 90% of power outages in Nova Scotia occur because of downed trees falling on power lines. It argued that even in this context, NS Power's OM&G vegetation management costs for 2018, 2020 and 2021 have been significantly below its twelve-year average. NRR goes on to state:

> 20. NSP's responses to the Consumer Advocate's questions on vegetation management suggest that investment towards vegetation management is not consistently focused on distribution, highlighting a deficiency in NSP's operational priorities which would reasonably be expected to impact reliability of service.
>
> …
>
> 22. …NRR takes the position that NSP's maintenance budget is some combination of deficient and misallocated to purposes that do not offer sufficient return to ratepayers in terms of system reliability.
>
> [NRR Closing Submission, p. 5]

[342] However, the Board agrees with NS Power in its Reply Submission, where the Company notes that NRR's focus on only OM&G vegetation management costs does not provide a full picture of NS Power's vegetation management investment. NRR's position ignores the capital investment that NS Power has made with respect to vegetation management. Undertaking U-39 asked NS Power to provide a table describing the Company's vegetation management costs from 2010 to 2021, including distribution and transmission OM&G and capital costs. The response to Undertaking U-39 provided as follows:

2010-2021 Vegetation Management Costs ($ million)

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020*	2021
Operating Expense	8.9	7.9	8.5	8.4	8.0	7.1	5.7	11.2	5.2	11.5	4.2	4.2
Capital Investment	0.7	0.9	1.0	2.2	0.8	1.2	7.0	11.1	19.1	14.3	10.4	16.4
Total Expenditures	**9.6**	**8.8**	**9.5**	**10.6**	**8.8**	**8.3**	**12.7**	**22.3**	**24.3**	**25.8**	**14.6**	**20.6**

* Vegetation management spending in 2020 was only $14.6 million because of operational restrictions during the height of the COVID-19 pandemic.

This table clearly shows that NS Power's total expenditures on vegetation management has increased significantly over the past five years.

[343] The Board also notes that NS Power's capital expenditures over $1 million related to system reliability, storm hardening and vegetation management are reviewed by the Board for prudency. Additionally, the Board continues to review NS Power's system reliability performance through the annual Performance Standards Review proceeding.

7.7 DSM Rider

[344] In its application, NS Power requested Board approval of a Demand Side Management Cost Recovery Rider (DCRR) to recover costs associated with DSM programs developed and delivered by EfficiencyOne, a third-party regulated utility. NS Power stated that it does not control the magnitude or scope of those programs, their execution, or the establishment of the funding levels. Those aspects are managed by EfficiencyOne and Board approval is required under a public regulatory process.

[345] Accordingly, NS Power stated that it is not appropriate or necessary for it to accrue positive or negative cost variances in DSM program spending. It noted that alignment of utility revenues with actual costs and promotion of regulatory transparency and efficiency would be achieved if DSM costs were segregated from its revenue requirement for separate tracking and recovery under the DCRR.

[346] In this matter, NS Power's proposed DCRR was initially based on DSM expenditures of $39 million during each of 2023 and 2024. This was later updated to

align with the expenditure levels of $53.1 million in 2023 and $57.5 million in 2024, as approved in the Board's *2023-2025 DSM Plan* decision (M10473).

[347] Parties to the GRA Settlement Agreement accepted NS Power's request for the DCRR, with certain amendments:

> Implementation of the DSM Cost Recovery Rider (DSM Rider) as it was applied for, but with the amendment set out in Section 13 of NS Power's Rebuttal Evidence such that NS Power, rather than EfficiencyOne, will make the annual application for the DSM Rider to the Board and further amended to remove the last two bullets on page 8 of the DSM Rider, as committed to in the oral hearing and in Undertaking U-40. In addition, the DSM Rider charge will be incorporated within the class energy charges (i.e. not segregated on customer bills). For greater certainty, the DSM Rider's allocation of costs to customers shall be consistent with E1's approved 2023-2025 Application. For customers taking service in the Wholesale or Renewable to Retail markets, recovery of DSM costs will be through direct billing by NS Power to such customers.
>
> [Exhibit N-155, p. 6]

[348] The proposed DSM Cost Recovery Rider consists of two components:

1) The Program Cost Recovery (PCR) component, which includes all estimated costs for the upcoming calendar year for the DSM Plan that has been requested by the Franchise Holder and approved by the Board. The PCR is computed for each rate schedule using the cost allocation methodology set out in the tariff;

2) The Balance Adjustment (BA) component, which is the difference between the amount billed in the previously completed calendar year from the application of the PCR unit charges and the actual cost of the approved DSM during the same previously completed calendar year. In order to enable incorporation of a full year's actual results, the BA will address differences in the year that is 2 years prior to the current PCR year.

[349] The DCRR also requires that on or before October 1 of each year, NS Power will file its application for approval of the DSM cost recovery charges to be effective on the following January 1. The cost recovery components will be forward-looking based on projected costs for the upcoming year. The true-up component will reflect the difference between actual costs and billed amounts for prior year DSM activities.

[350] In closing submissions, the only dissenting opinion about the DSM Cost Recovery Rider was expressed by NRR:

> 76. NRR generally supports the DSM rider as set out in the Settlement Agreement, but challenges NSP's position that simply because there is no direct linkage to the changes in cost and revenue amounts since 2014 to annual class DSM programing approved by the Board, that the proposed calculation of DSM costs must be based on the 2014 cost of service to satisfy amendments to s 64A of the *PUA*.
>
> [NRR Closing Submission, pp. 14-15]

[351] Another related item identified in the Final Issues List was DSM true-up of prior period variances (see matter M07151). This issue focused on true-up of variances associated with the DSM programs for 2015, 2016-2018, and beyond, in view of the DCRR termination as of January 1, 2015. In its Reply Submission dated February 23, 2016 in that matter, NS Power stated:

> … NS Power proposes that DSM revenues be trued up against actuals in accordance with how the previous true-up mechanism worked under the DSM Cost Recovery Rider (DCRR). Under this scenario, NS Power would compare recoveries and costs on an annual basis and ensure that the amounts are tracked in order to be appropriately allocated at the next rate setting procedure.
>
> [M07151, NS Power Reply Submission, p. 4]
>
> NS Power notes that many of the cost allocation issues before the Board in this matter pertain to how DSM costs are divided amongst and collected from the various rate classes.
>
> The Company recommends as follows:
>
> …
>
> - NS Power does not have a strong preference as to which cost allocation methodology is utilized, however, based on the submissions from the parties, the "Traditional Approach" to DSM cost allocation and true-up should be implemented.
>
> - True ups will be tracked annually and affected into rates at the time of the subsequent GRA.
>
> [M07151, NS Power Reply Submission, p. 7]

[352] In its Decision in Matter M07151, the Board approved NS Power's proposal to annually track comparisons of DSM cost recoveries to DSM expenditures, and then to adjust any required variances during the next GRA.

[353] In his evidence in the current GRA, Mr. Drazen addressed this issue and noted the following NS Power IR responses:

> There is no true-up of DSM variances from budget recovered in customer rates. There is a true up of variances between budget and payments by NS Power to E1 between contract periods (i.e. variances across a contract period are rolled forward as adjustments to future contract period payments).
>
> [Exhibit N-41, NSPI (NSUARB) IR-185]
>
> NS Power has updated the schedule comparing actual DSM expenditures to the approved E1 DSM budget amounts to the end of 2021…NS Power does not consider this to be a comparison to recoveries as these amounts, in particular the annual DSM class-specific recovery amounts, were not established through the most recent GRA-vetted Cost of Service Study (2014) for the recovery of DSM costs and have not been updated annually since that time in accordance with the Board-approved DSM program spending.
>
> [Exhibit N-38, NSPI (IG) IR-40]

[354] Mr. Drazen recommended that NS Power be directed to provide the originally proposed intra-class true-up for the Board's consideration. In responding to this recommendation, NS Power's Rebuttal Evidence stated that the changes in cost and revenue amounts since 2014 have no direct linkage to the annual class DSM programming approved by the Board. NS Power also noted that the variances should be a measure of DSM program funding and the associated revenues assumed to have been built into rates, if this had been assessed and reset each year, but that was not done. In addition, NS Power expects the 2023 DSM Rider amounts will recognize past class variances in DSM program spending, as may be appropriate.

[355] In canvassing this issue, Board IR-1 to John Todd of Elenchus, consultant to EfficiencyOne, asked whether he considered that NS Power's "allocation tables" and "variance analysis", in response to IG/Dal IR-40 (Attachment 2 Confidential), constituted reasonable proxies for such "class specific recovery amounts" until they are reviewed in an updated Cost of Service Study. His response was:

> Elenchus considers that NS Power's "allocation tables" and "variance analysis," in response to IG/Dal IR-40 (Attachment 2 Confidential), constitute a conceptually reasonable approach to determining the "class-specific recovery amounts", however, a careful review and cleanup is required.
>
> …
>
> Elenchus is of the view that the details of the methodology that are embedded in the NSPI's model require careful review prior to accepting as appropriate any of the embedded assumptions that were not determined and approved for each year by the NSUARB.
>
> [Exhibit N-98, E1 (NSUARB) IR-1]

[356] This issue was not addressed in the GRA Settlement Agreement or in Closing Submissions.

7.7.1 Findings

[357] The Board accepts NS Power's proposal to segregate DSM costs from its revenue requirement to facilitate separate tracking and recovery under the DCRR. This approach, including the true-up mechanism, will improve transparency and efficiency in appropriately allocating costs among rate classes. Most parties accepted NS Power's proposal to implement a DCRR, if it agreed to incorporate certain amendments as stated in the GRA Settlement Agreement. Accordingly, the Board approves the DCRR as referenced in the GRA Settlement Agreement.

[358] Recognizing that this GRA decision is being released after the October 1 DCRR filing date noted in the tariff, NS Power is directed to file updated DCRR charges for 2023 within its compliance filing.

[359] As the issue of DSM true-up for prior period variances was not addressed in the GRA Settlement Agreement, the Board makes no determination at this time. The Board assumes that NS Power and stakeholders will continue to discuss this issue and

directs that an update on this matter be filed no later than the first application to adjust the DCRR approved in this decision.

7.8 Cost of Service Study and Line Loss Study

[360] The Board released its *2013 Cost of Service Study* (*COSS*) decision in March 2014, 2014 NSUARB 53 (M05473). NS Power applied the Board's findings from that decision in the cost of service methodology for the present GRA. In the GRA Settlement Agreement, the parties agreed to a process in which an updated COSS and a Line Loss Study will be completed prior to NS Power's next GRA or December 31, 2025, whichever is sooner:

> NS Power must file a Cost of Service Study and a Line Loss Study prior to filing its next GRA or December 31, 2025, whichever is sooner. NS Power will provide for stakeholder engagement in the scoping and review of initial results, which will include consideration of bundled and unbundled services in an integrated manner as referenced in the Board's decision at para. [42] in 2021 NSUARB 126, prior to filing the final Studies. Board approval for the use of those Studies should occur as a part of the next GRA proceeding. Costs associated with the production, stakeholder engagement, and filing of these Studies may be deferred by NS Power and, subject to Board approval, recovered through rates subsequent to NS Power's next general rate application.
>
> [Exhibit N-155, pp. 6-7]

[361] In this proceeding, several concerns were raised about NS Power's cost of service methodologies applied in this GRA. These concerns included the use of the minimum system study for the classification of distribution costs, the cost classification and allocation for generation and transmission using a base load power methodology inherent in the Load Factor/3 Coincident Peak (LF/3CP) method, and the sub-functionalization of distribution costs between the primary and secondary distribution systems.

[362] Resource Insight stated that the relevance of the LF/3CP method had waned as NS Power's generation and purchased power mix had changed and was in transition. It said other cost allocation methods should be considered due to factors such as increased use of the Maritime Link to access 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.

[363] The reference in the GRA Settlement Agreement to the Board's *BUTU* decision [2021 NSUARB 126] highlighted the concerns expressed by Mr. Athas, the SBA's consultant, and Darren Rainkie, Board Counsel's consultant, about the growing integration of bundled and unbundled services in the developing modern power system:

> [42] As noted above, Mr. Athas supported the use of embedded costs to establish pricing under the BUTU Tariff to provide for consistent pricing for the same regulated services. In his view, all customers receiving the same service should be treated equitably, "whether the customer (or customer class) receives only one service from the utility or all services in a bundled offering." He felt NS Power should include bundled and unbundled services in an integrated cost of service study to "minimize or eliminate the potential for cross subsidization." The Board agrees that there are aspects of the services that are similar, and it is attracted to Mr. Athas' suggestion that costs relating to bundled and unbundled services should be considered together in an integrated cost of service study where any appropriate differences in the services can be considered.
>
> [*BUTU* Decision, 2021 NSUARB 126]

[364] Later in the *BUTU* decision, the Board again highlighted the concerns expressed about the integration of bundled and unbundled services offered by a utility:

> [74] In his pre-filed evidence, Mr. Athas said all forward-looking utilities should recognize their role in providing regulated unbundled services will only grow and he urged the Board to consider the present application "in the context of developing a foundation for costing unbundled utility services that can be applied in future unbundled service pricing" (Exhibit N-15, p. 9). Mr. Athas agreed with the transition of the BUTU Tariff to embedded cost of service-based pricing to provide consistency with bundled service class customers, but expressed concerns with NS Power's dated cost of service study given changes that have taken place in the decade since the study was prepared. He also questioned whether the parties and the Board would consider the same cost allocation methodologies when viewing bundled and unbundled services together.

> [75] Board Counsel consultant, Darren Rainkie, shared Mr. Athas' view that the proper way of dealing with bundled and unbundled services is through a cost of service study. In his testimony at the hearing, he referenced the four "Ds" driving the current energy transition: decentralization, democratization, decarbonization, and digitalization. He said a cost allocation study recognizing the "new transitional world" in terms of the energy market would be the preferable way to deal with and balance rate-setting factors.
>
> [*BUTU* decision, 2021 NSUARB 126]

In the *BUTU* decision the Board shared the concerns of Mr. Athas and Mr. Rainkie about the COSS.

[365] In its Pre-filed Evidence, Resource Insight also had concerns about what it perceived as NS Power's failure to address an earlier Board directive around updates to its Line Loss Study. The CA's consultant stated that, without these updates, it is likely that the cost of service is inaccurately allocated among customer classes, resulting in some customer classes having rates that are unfairly high. NS Power responded that while the updated load research sample was used to allocate the class coincident demands in the COSS, the line loss estimates in the GRA remained consistent with past applications. The Utility agreed that further work was required to refine the class level line loss estimates, but that such data was not readily available until AMI was fully implemented with its customers. It said that it was premature to undertake the Board's directive until the data was available.

7.8.1 Findings

[366] The parties agreed through the GRA Settlement Agreement that both a COSS and Line Loss Study must now be completed before the next GRA or by December 31, 2025, whichever is sooner. The parties also agreed to a stakeholder engagement process for the scoping and review of initial results.

[367] The Board concurs that the COSS and Line Loss Study should be updated to reflect a number of developments impacting NS Power's system since the 2013 COSS, including the greater integration of wind and other renewables, the addition of gas fired generation, the phasing-out of coal fired generation, the use of grid-scale battery storage, the increased reliance on purchased power agreements, and the integration of bundled and unbundled services, among other issues. All other cost allocation methodologies should be reviewed for their continued relevance and application. The Board concludes that this provision of the GRA Settlement Agreement is appropriate and directs the process and timeline as agreed to by the parties. The Board directs that semi-annual progress reports must be filed with the Board starting January 31, 2024.

[368] As part of the proposed settlement for NS Power to complete the COSS and Line Loss Study, it was agreed, subject to Board approval, that the costs associated with the production, stakeholder engagement, and filing of these studies may be deferred by NS Power and recovered through rates after the next general rate application. The Board approves this deferral.

7.9 Accounting and Financial Matters

7.9.1 Materiality Thresholds

[369] In 2019 NS Power applied to the Board for revision of some of its accounting policies. As part of its review of the accounting policy changes, the Board reviewed NS Power's capitalization limits. In response, NS Power engaged KPMG to provide a jurisdictional scan related to its capitalization limits. In a letter dated October 9, 2020 (M09229), the Board directed NS Power as follows:

> The Board directs NS Power to propose revised thresholds that reflect either a fully analyzed administrative burden or that brings NS Power in line with the average of comparable utilities and provide a sensitivity analysis that demonstrates the impact of incorporating such results in the next rate case.

[370] In response to this directive, NS Power engaged KPMG to update its previously completed jurisdictional scan and included its evidence as Appendix 8F in the application. In its evidence, Grant Thornton concluded the following:

> Based on the updated jurisdictional scan, we believe NSPI has demonstrated they are in line with the average of comparable utilities and therefore recommend that the Board accept NSPI's position that no revision to the capitalization materiality thresholds included in Accounting Policy 1560A are necessary at this time.
>
> [Exhibit N-56, p. 80]

[371] Based on the analysis provided, the Board is satisfied that the materiality thresholds in place are in line with the average of comparable utilities and, therefore, appropriate.

7.9.2 Depreciation Study

[372] NS Power noted in its application that a depreciation study would typically precede or coincide with a GRA process. Prior to the current 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. In response to the Board's IRs on the GRA Settlement Agreement, NS Power stated that it intends to file a depreciation study in advance of its next GRA and has proposed the use of the DDA to separately deal with the retirement of the coal plants. It further stated that the consultative process for the DDA will inform the scope of the depreciation study, including whether it will address the thermal assets.

[373] Grant Thornton stated in its evidence that it does not agree with NS Power's position to forego completion of a depreciation study on NS Power's asset pools not impacted by the retirement of the coal plants. In its Closing Submission, NRR requested that the Board order NS Power to complete a depreciation study.

[374] The Board agrees that a depreciation study is necessary and directs NS Power to file a depreciation study prior to its next GRA. The Board further directs NS Power to include the scope of the depreciation study as part of its DDA consultative process with stakeholders and the resulting report on that process.

7.9.3 Taxes

[375] In its evidence, Grant Thornton made the following conclusion and raised two issues with respect to NS Power's tax expense:

> Income tax expense for forecast 2021 and proposed 2022, 2023 and 2024 appear consistent with substantively enacted corporate income tax rates and forecast except in relation to the following two matters:
>
> • 2024 includes $5 million income tax expense that requires further examination to ascertain if the balance is an appropriate revenue requirement cost.
>
> • We identified a $35 million amount in rate base pertaining to a deferred income tax asset for non-capital losses potentially created by Part VI.1 tax deductions. We recommend that all activity related to Part VI.1 tax should be included in unregulated activities of NS Power and excluded from rate base.
>
> [Exhibit N-56, p. 49]

[376] NS Power, in its Rebuttal Evidence, explained that the $5 million expense highlighted by Grant Thornton was an adjustment required to account for a portion of the income tax loss that was unavailable to be carried back to prior years. In response to Undertaking U-13, NS Power further explained that the amount available to be carried

back was limited because the legal entity taxable income in the previous three years was lower than the taxable income on a regulated entity basis.

[377] The Board notes that, generally, the income tax impacts of all unregulated expenses should be segregated along with those unregulated expenses and should not, therefore, have any impact on test year forecasts. However, in the context of the test years in question, the government-imposed rate-cap results in such an adjustment being moot.

[378] In its Rebuttal Evidence, NS Power confirmed that the $35 million income tax asset noted above is, in fact, related to the Part VI.1 tax deductions, and explained that it is offset by a liability due to Emera such that there is no overall impact on rate base. NS Power also noted that it defers to the Board in relation to the treatment of the Part VI.1 tax transfer as unregulated.

[379] The Board agrees that since the Part VI.1 tax deductions and related transactions with Emera are unregulated activities, these items should be excluded from rate base and from the regulated financial statements of NS Power. The Board directs NS Power to exclude all Part VI.1 tax transactions and amounts from its regulated statements in the future, and to adjust for any amounts currently included in the regulated financial statements.

[380] Intervenors and the Board have expressed concern over NS Power's growing deferred income tax liability. This liability is due, in part, to timing differences associated with the accounting depreciation being different from the capital cost allowance for tax purposes. In response to Board IR-156, NS Power confirmed that it follows Accounting Policy 5900 by claiming sufficient capital cost allowance to minimize

cash taxes. Grant Thornton, in its evidence, noted this policy is prudent and almost universally applied. It also noted that this approach results in reduced current cost of service and increased future cost of service. Grant Thornton recommended the Board closely monitor the deferred income tax liability and its impact on cost of service through existing reporting processes. The Board agrees.

7.10 Amortization of Annapolis Tidal Generation Facility

[381] In its application, NS Power applied to create a regulatory asset for the Annapolis Tidal Generation Facility to recover its remaining net book value (NBV) over a 10-year period, representing an annual expense of $2.5 million. The plant is currently in rate base earning the allowed return and permitting NS Power to collect depreciation expense of about $800,000 per year through rates.

[382] In 2021, NS Power applied to the Board for approval to treat the plant as "Not Used and Not Useful" and proposed to amortize its undepreciated value and remaining Construction Work in Progress (CWIP) (in the total approximate amount of $27.7 million) over a 10-year period under Accounting Policy 6350. The Board concluded that NS Power had not shown that decommissioning the plant was the least cost option for ratepayers. Accordingly, the Board also found that it was premature to approve the proposed 10-year amortization under Accounting Policy 6350. The Board added that it would keep the matter in abeyance pending further information from NS Power, directing that NS Power provide a status update by January 31, 2023. The Board's *Annapolis Tidal Accounting Treatment* decision, 2022 NSUARB 2 (M10013) was released January 13, 2022, two weeks before NS Power filed the current GRA.

[383] When asked in IRs why it had forecast the amortization of the Annapolis Tidal Generation Facility in the GRA as a proposed regulatory asset over a 10-year period, NS Power replied:

> NS Power produced the revenue requirement forecast before it received the January 13, 2022 decision from the NSUARB on the proposed accounting treatment. The revenue requirement forecast included the 10-year amortization period.
>
> …
>
> NS Power has reviewed the Decision and the matters raised by the Board regarding further analysis to demonstrate the least-cost option for the facility. NS Power will address these matters before submitting a new application to the NSUARB. The timing of such an application has not been determined.
>
> [Exhibit N-41, NSUARB IR-70]

[384] Grant Thornton expressed concern about NS Power's request in the GRA to include the Annapolis Tidal Generation Facility in its regulatory amortizations:

> NS Power has proposed to recover the retired assets associated with the Annapolis Tidal Generating Station with a remaining net book value excluding land of $25.4 million at December 31, 2021 (includes $23.5 million in PPE and $1.9 million in CWIP) over a ten-year period. This would result in a $2.5 million revenue impact annually over the test period of 2022F-2024F. In Matter M10013 (2022), the Board was unable to conclude if the Generating Station is not used or useful, and therefore the application has been held in abeyance. According to NS Power, the ten-year amortization proposed in this GRA was done so before Matter M10013 was held in abeyance. NS Power has stated they have reviewed the decision of M10013 (2022) and will address it with a new application to the Board. If the regulatory deferral and proposed amortization is not approved in the GRA, the impact on revenue requirement would be a reduction in amortization of $2.5 million each year, partially offset by higher depreciation, interest and equity costs due to the asset being included in property, plant and equipment instead of a regulatory asset.
>
> [Exhibit N-56, p. 51]

[385] However, in its response to an IR about the GRA Settlement Agreement, NS Power confirmed that it still intends to include the Annapolis Tidal Generation Facility in its forecast regulatory assets, for which NS Power seeks Board approval to recover financing costs at the Company's weighted average cost of capital [Exhibit N-156, Attachment 1].

7.10.1 Findings

[386] The Board recognizes that there was a short intervening two-week period in January 2022 between the Board's release of the *Annapolis Tidal Accounting Treatment* decision and the filing of NS Power's GRA. In those circumstances, it was not unreasonable for NS Power to assume that its application about the Annapolis Tidal plant might be approved by the Board and to prepare its GRA forecasts on that basis. However, ultimately, the Board did not approve that application and it is currently in abeyance. Despite the Board's ruling, NS Power continues to ask that the plant be included in its regulatory amortizations for the test years.

[387] In the Board's opinion, the inclusion of the Annapolis Tidal Generation Facility in NS Power's regulatory amortizations is in direct conflict with the Board's prior decision on that same point. A finding on that proposed accounting treatment is still premature while the matter is being held in abeyance. In the circumstances, the Board does not approve the component of the GRA Settlement Agreement that provides for the regulatory amortization of the Annapolis Tidal plant. The Board directs that the plant remain in property, plant and equipment.

7.11 Maritime Link Transmission – Capital Work Orders

[388] In this GRA, NS Power requested approval of four transmission capital projects (total cost of $44,687,437) related to the Maritime Link and the energy flows from the Muskrat Falls Generating Station. The application stated that those assets have been depreciating at shareholder expense since their in-service dates and are included in the GRA forecast at their net book value. In its May 3, 2022, response to Board IR-95, NS

Power provided annual depreciation amounts for each of these projects. The individual amounts shown below result in a total annual depreciation expense of $1,336,786:

- CI 43324 - L6513 Rebuild / Upgrade Line Terminals
  Cost $18,626,428; In-service date 2018/07; Annual Depreciation $717,755

- CI 43678 - Separate L8004/L7005 on Canso Crossing Double Circuit Tower
  Cost $20,387,278; In-service date 2018/07; Annual Depreciation $485,407

- CI 45066 - Upgrade L6511 and L7019 Thermal Rating
  Cost $2,691,017; In-service date 2018/01; Annual Depreciation $69,794

- CI 45067 - 67N Onslow 345 KV Node Swap
  Cost $2,982,714; In-service date 2018/01; Annual Depreciation $63,830

[389] Three of the four projects were initially submitted for approval in 2014 and 2015. Following a review of those applications, Board approval was not granted. CI 43678 was not previously submitted.

[390] Counsel for the Industrial Group and Dalhousie University canvassed the requirement for these transmission projects during the hearing, with reference to NSPML's initial application in the 2013 Maritime Link matter M05419. At that time, three of the transmission projects, estimated to cost $31.5 million, were identified as being required to allow Nalcor to deliver Nalcor Surplus Energy to the New England and New York markets. In that proceeding, it was noted that NS Power would incur capital, maintenance, and redispatch costs to enable Nalcor's wheeling requirement:

> As part of the exchange for 20 percent of the output from Muskrat Falls, Nalcor requires a transmission path through Nova Scotia and New Brunswick to allow Nalcor to deliver Nalcor Surplus Energy to the New England and New York markets.
>
> …
>
> …Based on NSTUA requirements and expected quantities of Nalcor Surplus Energy, NS Power is expected to incur capital upgrade, maintenance and redispatch costs associated with providing a path for the Nalcor Surplus Energy from the interconnection point with the Maritime Link at Woodbine through to the Nova Scotia / New Brunswick border.

…

Figure 8-1 Nova Scotia Power Network Upgrades[57]

NSPI Network Upgrades	Forecasted Investment					
	2013	2014	2015	2016	2017	Total
1 L-6513 Rebuild/Upgrade Line Terminals	1,610,000	8,168,000	322,000			10,100,000
2 Strait Crossing / Separate L-8004/L-7005	108,000	972,000	4,752,000	4,752,000	216,000	10,800,000
3 L-6511/L-6515/L-6552 Upgrades		1,060,000	9,540,000			10,600,000
	$1,718,000	$10,200,000	$14,614,000	$4,752,000	$216,000	$31,500,000

The cost to redispatch NS Power's fleet is also an estimate at this point and will depend on the amount and timing of the Nalcor Surplus Energy. Based on projections of Nalcor Surplus Energy, the estimated cost of redispatch is forecast to range from $6-8 million annually.

[Exhibit N-123, pp. 2-4]

[391] This was confirmed by NS Power during questioning by Ms. Rubin:

Q. So at the time, it was anticipated that Nova Scotia Power would need to undertake the following upgrades. And three projects are listed there, which, as you know, totalled about $31.5 million?

A. (MacDonald) Yes, that's what I see on the table at Figure 8.1.

Q. Okay. And those three projects are included among those that you have in fact filed for, plus one additional project, the CANSO Crossing Double Circuit?

A. (MacDonald) Yes.

Q. Okay. So at the time these three projects were, I guess, very preliminarily estimated at about $10 million each, and then in addition -- in addition to those capital costs, NSPI was expected to incur redispatch costs in range of 6 to $8 million?

A. (MacDonald) Yes, that's what I'm reading here in this paragraph.

Q. Okay. Plus operating cost?

A. Yes.

Q. And based on the projections of the Nalcor surplus energy that was being wheeled through Nova Scotia across these transmission paths, it was expected that fees from that wheeled-through energy, by Nalcor to third parties, would offset the capital expenditure, the redispatch cost, and the system maintenance cost; correct?

A. (MacDonald) Yes, that was part of it. And the "or" with that is, or benefits to the Nova Scotia system or Nova Scotia customers would otherwise be greater than that alternative you're speaking of.

[Transcript, September 12, 2022, pp. 270-272]

[392] As noted above, the primary reason for these projects was to facilitate Nalcor's intended energy export to third parties beyond Nova Scotia. They were not identified as a necessity for continuing to serve native load in Nova Scotia prior to the Maritime Link coming online. In its IR responses in matter M06525, NS Power stated:

> Response IR-5:
>
> (a) Associated with the Maritime Link project is the requirement to export 330 MW in summer and 150 MW in winter from Nova Scotia to New Brunswick. This requirement necessitates an increase of Onslow Import (ONI) level from 1,025 MW to 1,220 MW. With the increased transfer levels, the loss of the common breaker 67N-812, which takes out both 345 kV lines L-8002 and L-8003, would result in the remaining 230 kV lines being unable to support the post contingency load flow resulting in a system collapse.
>
> (b) This potential can start when the Maritime Link energy flowing into NS is 300 MW or above.
>
> (c) That potential does not exist prior to the Maritime Link, provided that ONI is below 1,025 MW.
>
> [M06525, Exhibit N-4, NSPI (NSUARB) IR-5]
>
> Response IR-6:
>
> (a) The additional power transfer capability will be necessary when the Maritime Link comes online in late 2017…
>
> <u>Prior to the Maritime Link coming online, the additional power transfer capability is not strictly needed to accommodate new load or generation</u>…[Emphasis added]
>
> [M06525, Exhibit N-4, NSPI (NSUARB) IR-6]

[393] The requirement for these transmission projects and their cost recovery were canvassed extensively by parties at the hearing. The following series of Board questions also explored the reasons for those projects:

> So the first question I want to ask is if the four Maritime Link Projects were not constructed, would the Nova Scotia Block be able to flow into Nova Scotia for use by Nova Scotia ratepayers?
>
> **A.** (MacDonald) For just the Nova Scotia Block to flow, my understanding is that not all aspects of the four projects would have been required, but that's one part of the overall transaction. So, no, not necessarily.
>
> **Q.** So no?

A. (MacDonald) Not for, in isolation, the Block, but I expect we should talk about more than that.

Q. When you say talk about more than that, what are you referring to?

A. (MacDonald) I'm referring to the other energy flows that were forecast whether to be left in province or for export, and the collection of related transition [transmission] projects, the four projects that go with all of that.

Q. Yeah, I guess my question is putting, you know, flows, energy flows, I guess, that were requested by Nalcor to flow through New Brunswick, were those four projects required -- if there was no requirement to flow this energy to New Brunswick, would those four projects have been required to accommodate flow of the Nova Scotia Block for use by Nova Scotia ratepayers.

A. (MacDonald) The projects are required for the flows into Nova Scotia beyond the Block…

…

Q. Those other energy flows are over and above the Nova Scotia Block.

A. (MacDonald) Yes.

Q. All right. And if I understand the Maritime Link Project correctly, at the time the Maritime Link was put into service, the intent was to retire Lingan 2.

A. (MacDonald) Yes.

Q. It hasn't quite worked out that way, but that was the intent. So the way I read that is it was sort of a like-for-like replacement and that, you know, the Maritime Link energy would provide a renewable source of energy that replaced coal-fired energy from Lingan 2.

A. (MacDonald) Right, which is why, in the situation where precisely Lingan 2 off and precisely Nova Scotia Block on, you could say that the transmission investments for that exact situation, but for also considering the rest of the energy flows, you could maybe in this -- I talked about this the other day, about the timing or how you might stage the work plan to line up when you would do those projects to do Block-plus. But the way it was done because of how the entirety of the transaction and the project was ultimately approved, and the economics of it taken together was that those projects were completed at the same time and then, as you alluded to, the block flowing or not and then the timing of Lingan 2 has been different, but to the benefit of Nova Scotia customers and the way the system can be staged to do many things now, including the flows of the Block, that's definitely a benefit to customers.

Q. When you talk about the other energy requirements over and above the Block, is that just strictly related to the energy flows that were expected to wheel through for Nalcor?

A. (MacDonald) No, I'm talking about the capability to keep larger flows in province.

Q. Keep larger flows from surplus energy, market-price energy?

A. (MacDonald) Yes.

Q. Over and above Nova Scotia Block.

A. (MacDonald) Yes. And perhaps the supplemental energy, although sometimes the labels escape me.

[Transcript, September 14, 2022, pp. 727-732]

[394] The capacity associated with the NS Block is 153 MW. Since the energy and capacity from the NS Block is intended to displace generation from Lingan Unit 2 (148 MW), thereby essentially maintaining equivalency on the provincial grid, the Board understands that the above reference to exporting 330 MW in summer and 150 MW in winter from Nova Scotia to New Brunswick is in addition to the NS Block.

[395] In its direct evidence, NS Power stated that OATT tariff revenues from wheeling Nalcor energy through Nova Scotia were expected to offset the cost of those capital projects:

> The submitted capital applications were not approved by the NSUARB at that time. In its reasoning the Board expressed similar comments to those noted in the 2014 ACE Plan proceeding. NS Power affirmed in those written hearing proceedings that the tariff revenues would likely offset the full cost of the transmission upgrades, and the Company would not seek to put costs into rate base in compliance with the Board's 2014 ACE Plan directive.
>
> With respect to the offsetting of capital costs by tariff revenues, NS Power provided the following in response to Board questions regarding CI 45067:
>
>> Consistent with the submissions during the Maritime Link hearings, the cost of these capital investments (i.e. annual financing, depreciation, operating costs, etc.) and redispatch requirements are expected to be offset by tariff revenue related to Nalcor energy transported across NS Power's transmission system to third parties over the term. The forecast tariff revenues will be applied to reduce the amount to be recovered from Nova Scotia Power's customer base and to reduce the associated rates developed through General Rate Applications.
>>
>> A potential exception is if it is determined to be in customers' interests for NS Power to acquire additional Nalcor energy (market energy), the tariff revenue recovered from Nalcor may be less than that included in the tariff and less than that applied for the purposes of developing general customer rates. Such decisions to purchase Nalcor energy will be tracked and take into account the foregone tariff revenue prior to a determination that acquisition of the energy is in the best interests of customers.

[Exhibit N-16, p. 65]

[396] Following-up on Ms. Rubin’s questioning, Board Counsel sought clarification on how the transmission project costs would be offset if the OATT revenues received from Nalcor for energy transport across Nova Scotia were diminished due to NS Power retaining Nalcor surplus energy for use within Nova Scotia:

> **Q.** Okay. So the bottom line you're saying is the “or” piece that you mentioned the other day, which is that you're retaining the surplus energy, market energy, rather than shipping it through to New Brunswick will count for purposes of deciding whether it's revenue neutral to Nova Scotia Power's customers.
>
> **A.** (MacDonald) Yes, and that I would expect that as with any other review of how we dispatch the system, be that FAM or otherwise, that that has an ongoing process to test for that, and ---
>
> **Q.** Right.
>
> **A.** (MacDonald) --- that the transmission investments that we're talking about here, while to enable to path, also enable the way the energy will move around depending on the amount of market energy or surplus energy is being ---
>
> **Q.** Well ---
>
> **A.** (MacDonald) --- left to Nova Scotia at any given time.
>
> **Q.** But you stand by this evidence?
>
> **A.** (MacDonald) Yes.
>
> **Q.** And it will be up to the Board to decide after NSPI bills the shortfall on the tariff side to NSPML, for NSPML to then seek approval for that in its assessment and demonstrate the benefit to the Board?
>
> **A.** (MacDonald) Yeah…
>
> [Transcript, September 13, 2022, pp. 620-622]

[397] In Industrial Group and Dalhousie University IR-33, NS Power was asked to provide the monthly transmission tariff revenues from Nalcor for energy wheeled through Nova Scotia since the Maritime Link was placed in service. During the hearing, NS Power was asked to confirm, by way of an undertaking, that the monthly revenues provided in that IR response were in fact tariff revenues received from Nalcor for surplus energy wheeled through Nova Scotia. In its Undertaking U-3 response, NS Power stated:

> … This transmission service was not solely for Nalcor Surplus Energy being sold to third parties, but rather primarily for energy purchased from third parties and wheeled through Nova Scotia between the New Brunswick border and Newfoundland and Labrador.
>
> [Exhibit N-152, Undertaking U-3, pdf p. 8]

[398] NS Power's response to Industrial Group and Dalhousie University IR-33 also stated that tariff revenues for 2022, 2023 and 2024 were not included in any revenue assumptions for this GRA because it does not expect material tariff revenues going forward. NS Power said it intends to maximize purchases of available energy from Muskrat Falls, which means there will be less energy wheeled through Nova Scotia by Nalcor, and therefore, less OATT transmission revenue will be received. In that same IR response, NS Power stated that these additional energy purchases will create more value for NS Power's customers than would be created by flowing this energy through the province and collecting the tariff revenues.

[399] During the hearing, NS Power was also asked, by way of an undertaking, to provide an economic analysis to show that the forecast surplus energy purchases plus the OATT revenues over the test period would offset the related capital costs of the Maritime Link transmission projects. In its partially confidential response in U-64, NS Power provided results of a modeling analysis which compared costs assuming purchases of certain quantities of Nalcor surplus energy against the alternative of no Nalcor surplus energy being purchased. It stated:

> NS Power completed a Plexos run to compare the fuel refresh forecast to a scenario in which the Company did not have access to market-priced energy over the Maritime Link. The scenario in which NS Power did not have access to market-priced energy over the Maritime Link resulted in forecast greater fuel costs…
>
> [Exhibit N-152, Undertaking U-64, pdf p. 607]

7.11.1 Findings

[400] Having reviewed the current transmission capital project applications, along with related filings and transcripts, the Board's understanding continues to be that the primary reason for those projects is to enable Nalcor to transmit energy through Nova Scotia to third parties in other jurisdictions. They were not needed to accept the 153 MW NS Block, which is intended to displace similar capacity from Lingan Unit 2.

[401] The Board also notes NS Power's statements that it intends to maximize purchases of available energy from Muskrat Falls, which means that less transmission revenue will be received, but greater value may be created for customers. It is not clear whether that surplus energy purchase will be displacing energy currently generated by other Lingan units or other coal-fired generators. However, experience to date with receiving even the NS Block of energy has been poor. Ongoing delays with Nalcor's commissioning of the Labrador Island Link continue to highlight concerns about the value that might be created for Nova Scotia customers.

[402] It is incumbent upon the Board to highlight its concerns stated in earlier decisions. In its *2017 ML Interim Assessment* decision [2017 NSUARB 149], the Board stated:

> [153] NSPML indicated that it wants to have the Final Assessment hearing during 2018. The Board is not prepared to hold the Final Assessment hearing until it knows that the NS Block is being delivered in accordance with the original bargain. This will enable the Board to reserve whatever regulatory options may be available to it in the event of further unfortunate news.
>
> …
>
> [155] However, the Board is not prepared to approve the final assessment until it is confident the ratepayers will get what they bargained for - the NS Block, Supplemental Energy and Nalcor Market-priced Energy.

[403] That position was reiterated in the *2019 ML Interim Assessment* decision [2019 NSUARB 156], the *Final Project Costs* decision [2022 NSUARB 18] (M10206), and in the recent *2023 ML Cost Assessment* decision [2022 NSUARB 191] (M10708).

[404] In the *Final Project Costs* decision, and repeated in the *2023 ML Cost Assessment* decision, the Board also stated:

> [19] As of the date of the hearing only approximately 19% of the NS Block and Supplemental Energy had been delivered for the period commencing August 15 to the end of November 2021.
>
> [20] …The Board has noted in the past that NSPML and NS Power have over-promised and underdelivered when they describe benefits from the Maritime Link. In the 2017 interim assessment hearing, when NSPML was arguing that the Maritime Link was used and useful even in the absence of NS Block, NSPML and NS Power stated that energy and other benefits in excess of $120 million in 2018 and 2019 were expected. In fact, those benefits were less than $5 million per year in each of those years.
>
> [21] One might ask why the Board set these conditions in the *2017 Decision* and repeated them in every interim assessment since. That turns on the phrase "this will enable the Board to reserve whatever regulatory options may be available to it in the event of further unfortunate news".
>
> [22] The Board was preserving, for the benefit of ratepayers, the full measure of its regulatory authority to deal with what that "unfortunate news" might turn out to be.
>
> [*Final Project Costs* decision, pp. 13-14]

[405] The Board concludes that it must continue to "reserve whatever regulatory options may be available to it in the event of further unfortunate news". Therefore, the Board defers allowing the inclusion of the above-mentioned four transmission projects into rate base until NS Power can demonstrate 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. If this threshold test has not been met by NS Power's next GRA, NS Power may seek the Board's approval to include the transmission projects in its rate base if it can demonstrate that there is justification for doing so.

7.12 Bill payment, credit and collection matters

[406] In the Board's *2013-2014 GRA* decision, [2012 NSUARB 227] (M04972), the Affordable Energy Coalition, the CA and NS Power reached a settlement agreement establishing a consultative process "with a view to resolving bill payment, credit and collection matters affecting low-income residential customers". The Board described this as a positive development and endorsed the agreement, incorporating its terms into its final Order.

[407] The Board received a report in 2013 following the consultative process and incorporated its recommendations into NS Power's rules and regulations. In its Opening Statement in the present GRA, the Affordable Energy Coalition noted that there has been no formal evaluation of those changes. In both its Opening Statement and its Closing Submission, it requested a process to evaluate the changes approved in 2013, to examine if further changes are needed, and to "establish a systematic evaluation methodology". The Affordable Energy Coalition added that affordability most affects low- and modest-income households:

> …They are the ones who face disconnection most often and who most often must choose among different necessities when faced with high energy costs. This is more acutely true today due to recent fossil fuel price volatility and current high fuel prices.
>
> [Exhibit N-105, p. 2]

[408] In its Closing Submission, the Affordable Energy Coalition filed a letter from NS Power dated November 24, 2022, confirming the Utility's commitment to engage with the Affordable Energy Coalition and CA to review the outcomes related to credit and collections from the 2013 changes to NS Power's Regulations for the benefit of low-income residential customers, and to consider any additional changes that could assist low-income households. In its Closing Submissions, the CA confirmed he would participate in such discussions.

[409] The Affordable Energy Coalition added that this review should be undertaken with the explicit direction of the Board with a report back to the Board for its consideration and approval of any changes it deems beneficial.

7.12.1 Findings

[410] As noted in the Board's letter finalizing the Issues List for this matter, affordability is one of many issues to consider when setting rates that are just and reasonable. Indeed, the Board is mindful that electricity rates are already challenging for many and that Nova Scotia is reported to have one of the highest rates of energy poverty in the country. In its *2013-2014 GRA* decision, the Board noted it "receives literally hundreds of letters and emails a year from consumers who are struggling to pay their power bills and at the same time manage the cost of home heating, medication, groceries, etc." [para. 110]. The Board also received many letters of comment in the present matter outlining the impact of power rates on low- and fixed-income customers.

[411] The proposed review and consultative process has the commitment of NS Power, the Affordable Energy Coalition and the CA. The Board is pleased to endorse this initiative aimed at lessening the impact of power rates on low- and fixed-income residential customers. Accordingly, the Board directs that the three parties engage in a review process to evaluate the impact of the changes approved in 2013, to examine if further changes are needed, and to establish a systematic evaluation methodology that can be applied to future changes to NS Power's Regulations. The Board directs that a report be provided by April 30, 2023.

7.13 Miscellaneous charges and regulations

7.13.1 Customer Charges

[412] In its application, NS Power identified a significant increase to the customer charges in the Domestic Class and the Small General Class tariffs based on its cost of service:

Figure 12-2: 2022-2024 Customer Charges Based on Cost of Service

Customer Charge	Units	Current 2022	Proposed for 2022	Proposed for 2023	Proposed for 2024
Domestic Service Tariff	$/mo.	10.83	21.75	21.95	21.99
Domestic Service Time-of-Day Tariff	$/mo.	18.82	21.75	21.95	21.99
Small General Tariff	$/mo.	12.65	24.45	24.15	24.07

[Exhibit N-16, p. 99]

[413] The Utility proposed to phase-in the increase over the test years to the full amount in the 2024 test year.

[414] The customer charges have not changed since the early 2000s. These charges are intended to recover retail costs to serve a customer that are largely

independent of consumption levels, such as metering, customer care and billing costs, and a customer-related portion of the distribution system costs. Concentric (Dane and Rimal), NS Power's consultants, noted that since these costs are classified as being customer-related within the COSS, it is appropriate to recover them through the customer charges [see: Exhibit N-17, Appendix 12A, p. 26]. With the passage of about two decades, NS Power stated the customer charges now fall significantly short of the costs these charges are intended to recover. For the Domestic Charge, NS Power stated that the current $10.83/month customer charge recovers less than half of the costs that should be recovered in this charge and is among the lowest in Canada (and is less than half of the charge in the other Maritime provinces). Accordingly, NS Power proposed to phase-in the increases to the customer charges.

[415] Further, NS Power noted that, applying the updated COSS, the observed price gap between the current customer charges and the proposed charges results in cross-subsidization across customer classes and causes inflated volumetric class energy charges:

- The under-recovery of fixed customer costs in the Customer Charge means these costs are being recovered in the inflated volumetric class energy charges. At a time when customers are making investment decisions in alternative energy sources based on the energy price of the Company's bundled service offerings, which are largely composed of embedded fixed costs that do not change with sales volume, this situation is contributing to cost transfers occurring within classes and will result in uneconomic decisions for participating and non-participating customers.

[Exhibit N-16, p. 98]

[416] It is important to note that the Domestic and Small General classes have customer charges, but do not have demand charges. The remaining distribution, transmission and generation costs are recovered through the Domestic and Small General class energy charges. NS Power noted that the increases in the revenue from

the customer charges will place downward pressure on the class energy charges. For example, the increase from $10.83/month to the proposed $21.99/month in the 2024 Domestic Class customer charge would reduce the energy charge in this class by approximately 1.4 cents/kWh. The impact of these customer charge increases will differ according to customer consumption levels. Thus, customers with higher loads for whom the customer charge makes up a smaller portion of their bill will experience a smaller increase in percentage terms.

[417] Resource Insight had concerns about the proposed customer charge increases. As noted earlier in this decision, they had concerns about the "minimum system" methodology employed by NS Power under the COSS to classify distribution poles and wires costs attributable to customers and among the customer classes. They recommended that the Board direct NS Power to prepare a new COSS before applying changes to the customer charges.

[418] Ms. Whited, of Synapse, also had concerns about the proposed increases. Like Resource Insight, she also focused on customer impacts across different usage and income levels and the view that higher energy charges promote conservation. She stated the proposed increases to the customer charges would dampen customer incentives to conserve energy and invest in energy efficient technologies, while potentially also harming low-income customers. In response to NS Power's assertion that rate design should support beneficial electrification on the system, she said this would be better addressed through dedicated electrification rates, rather than significantly increasing customer charges.

[419] However, in the GRA Settlement Agreement, the parties agreed to an increase to the customer charges, but at a 25% reduction to the originally proposed increase in the cost of service rate for 2023, with no phase-in:

> As applied for, but at the 2023 customer charges amount with an agreed to reduction of 25 percent of the proposed increase and no-phase in given there will only be a one-time non-fuel/non-DSM rate increase. (Per Figure 12-2, page 99 of Direct Evidence but with 25 percent reduction to the proposed increase: Domestic Tariffs $19.17/month; Small General $21.28/month.)
>
> [Exhibit N-155, p. 5]

[420] In his Closing Submissions, the CA noted that an important concession by NS Power on this point was that the Utility committed to perform an updated COSS, which will support a fully informed customer charge.

[421] However, NRR opposed any increase to the customer charge:

> 82. NRR opposes any increase to Customer Charges. The imposition of a fixed cost increase will disproportionately impact families with low monthly bills, including renters, as well as ratepayers who choose to invest in energy efficiency or solar power and should expect relief from power charges as a reward for their efforts.
>
> 83. The evidence of Chernick and Wilson explained that the customer charge is properly intended to collect the actual cost to serve a minimum usage customer, and that NSP's proposed increase and its justifications for it should not be accepted.
>
> …
>
> 85. Although the Settlement Agreement notes that the rates agreed between NSP and certain intervenors is 25% less than requested in the Application, NRR asserts that any increase in customer charges is unreasonable for the reasons discussed by Chernick and Wilson.
>
> [NRR Closing Submissions, p. 16]

[422] NS Power challenged NRR's submission:

> …the change in the Customer Charge will benefit families with high monthly bills and will incent those that possess efficiency products like heat pumps to utilize them, and for those that do not possess them, to make the switch. Given the Province's recent announcement regarding the funding of heat pumps for low-income Nova Scotians, it would have been expected that NRR was in favor of the Customer Charge increase, as this change will result in the heat pumps being cheaper to operate given the lowering effect of the increased Customer Charge on the Energy Charge.
>
> If the intended implication in NRR's argument is that customers with low monthly bills are low-income customers, the evidence on the record does not support such a contention. In

> fact, this proposition has been specifically rebutted by Concentric in its evidence demonstrating that research has indicated that the usage pattern of low-income and non-low-income customers are similar. In addition to this, one of the Letters of Comment received by the Board in this proceeding was from the Antigonish Emergency Fuel Fund Society (AEFFS), a registered charity with a mandate to support individuals and families in the Antigonish Town and County who have difficulty paying for winter heat because of inadequate incomes. In its letter, the AEFFS states: "It is worth noting that 60% of all clients use electricity as their primary source of winter heat." This means that 60 percent of the individuals and families represented by the AEFFS are high-volume users of electricity and would benefit from the increase in the Customer Charge, given its decreasing effect on the volumetric Energy Charge.
>
> [NS Power Reply Submission, p. 20]

[423] In NS Power's Rebuttal Evidence, Concentric (Dane and Rimal) described how some low and high-income customers differed in their energy usage:

> … some low-income customers live in older, poorly insulated houses that consume more energy. In addition, low-income customers will be less able to afford energy efficient appliances as compared to non-low-income customers. Conversely, some high-income customers could potentially be low users. For example, net metering customers, i.e., customer that own their own generation resources, are likely to be low users. In addition, high-income users are more likely to own vacation homes and potentially have lower usage, especially if the property is not occupied throughout the year.
>
> [Exhibit N-102, Appendix A, p. 8]

7.13.1.1 Findings

[424] The Board finds that it is reasonable for the customer charges for the Domestic Class and Small General Class tariffs to be updated to reflect the current COSS. In addition to representing customer-related costs more accurately, this will also avoid undue cross-subsidization across customer classes. While the Board is mindful that there remain questions about the current COSS, these issues will be addressed as the COSS is updated before the next GRA, as noted elsewhere in this decision.

[425] Further, the Board accepts NS Power's expert evidence that these increases to the customer charges will not disproportionately impact lower income customers. Those who use higher than average amounts of power, will see a corresponding decrease in their energy charges. Concentric noted from their research

that lower income customers are just as likely to be high use customers as customers with higher incomes. Indeed, the Board notes the above comments of the Antigonish Emergency Fuel Fund Society to the effect that 60% of its clients use electricity as their primary source of winter heat. For that majority, the increased customer charges will lower their energy charges.

[426] Taking into account all of the above, the Board approves the customer charge increases outlined in the GRA Settlement Agreement.

7.13.2 AMI Opt-Out Fee

[427] In its application, NS Power requested the following regarding meter reading:

> 1. Approval of NS Power's proposed monthly charge for providing non-standard meter service, at $3.67 per month for the following rate classes: Domestic Service, Domestic Service Time of Day, and Small General.
>
> 2. Approval of NS Power's proposed monthly charge for providing non-standard meter service, at $22.01 per month for the following rate classes: General, Large General, Small Industrial, Medium Industrial, Large Industrial, and the Municipal Tariff.
>
> 3. Approval of revisions to Regulation 7.1 (Schedule of Charges), and 5.1 (Meter Reading) as reflected in the attached in PR-03.
>
> 4. Approval to limit determination of the 2 percent threshold in Performance Standard 11 to customers with AMI meters.
>
> [Exhibit N-16, p. 117]

[428] The assumptions used in determining those proposed fees were provided in Figure 12-10 as shown below:

Figure 12-10: AMI Opt-Out Model Assumptions

Opt-Out Charge Assumptions	
Customer Opt-Out %	3%
Opt-Out Total Customer	14,415
Total Meter Reads Per Year	29,904
Time Required (Hours)	5,417
Expected Average Cost 2022-2024	
Costs (In Millions $)	
Total O&M	$0.6
Depreciation, Carrying Costs, Tax	$0.1
Total Annual Revenue Requirement (In Millions $)	**$0.7**
Monthly Charge (Former Bi-Monthly Read Customers, now Semi-Annual Read)	**$3.67**
Monthly Charge (Monthly Read Customers)	**$22.01**

[429] The Board notes that these calculations are based on a customer opt-out rate of 3%, which is higher than the 2% assumed in the AMI capital expenditure application (M08349). A more detailed cost breakdown is provided in Exhibit N-27, PR-02, Attachment 2, which shows the following projections for the former bi-monthly and monthly read customers:

Year	Bi-monthly	Monthly	Annual Readings	Annual Cost
2022	$3.07	$18.44	40,461	$746,186
2023	$3.47	$20.82	30,795	$641,158
2024	$3.66	$21.99	26,725	$587,571

[430] In matter M08349, the issue of reducing or eliminating a potential opt-out fee was raised. Possible options included customers sending their meter readings to NS Power, either by postcard or electronically. Such provisions are available under existing Regulations. This issue was again explored in the current GRA via IRs and in the hearing:

> **Q.** (Outhouse) And in Board IR-190, and there's no need to bring it up, NSPI was asked to:
>
> > …provide any analysis undertaken that might eliminate or minimize [the] opt-out fees by enabling customers to submit photo, email, or postcard readings in place of [actual] meter readings.

And Nova Scotia Power's response was that, "No such analysis was undertaken."

Is that still true? No analysis has been undertaken in that regard?

…

A. (Willett) Yes, that's correct. And there's a listing below that ---

Q. Yes.

A. (Willett) --- for -- that explains the reasons.

Mr. Outhouse: If you could just scroll down?

Mr. Willett: Yeah.

Mr. Outhouse: Thank you.

Mr. Willett: So with moving to two reads per year, there is some requirements by the company to ensure that we are charging customers an accurate bill. There is some concerns with having postcard reads, which are listed in the IR response, and with having two reads per year, and having one or both of those as a postcard read, the company has expressed the reasons that would be of concern withing [sic] this response.

BY MR. OUTHOUSE:

Q. Your first answer is that:

> Per Regulation 5.1, postcard reads are an exception-based process for obtaining meter reads to be used when [Nova Scotia] Power is unable to obtain an on-site reading.

A. (Willett) That's what the response says. Correct.

Q. It's my understanding that there's certainly that exception in 5.1, but 5.1 also has a provision for postcard meter readings in rural areas and states:

> Where electric service is supplied to a Customer in a rural area, the Company may adopt a post card meter reading system of monthly or bi-monthly meter reading.

Isn't that the case?

A. (Drover) That is the case. However, that works in a situation where we're reading six times a year. It definitely becomes more complicated when we're only reading twice a year in terms of getting that true read that Mr. Willett mentioned.

Q. Regulation 5.1 also states, in regards to the postcard readings:

> The Customer shall record on the postcard the reading showing on the meter as of the reading date and shall immediately return the card to the Company. In these circumstances, the Company may consider postcard meter reading to be actual meter readings.

A. (Drover) That is true; however, I think it's important to point out that with AMI meters, they are more complicated to read than the traditional meters that we have. They cycle through various forms of information and to get the exact read of what consumption is, can be challenging.

Q. Sorry. Did you say AMI meters or non-AMI meters?

A. (Drover) Both, to be honest.

So the traditional analog meters are more complicated. Even the new meters for opt-out will be the AMI meters with the smarts turned off. The new meters are digital and cycle through.

So over time, it will become more complicated.

[Transcript, September 21, 2022, pp. 1948-1952]

[431] In Exhibit N-37 of matter M08349, NS Power provided an estimated total annual opt-out cost of $1,536,703. Board IR-3 [Exhibit N-37] asked for a calculation of the monthly amount that would be applied to each customer if the total annual cost remained with the total customer base. NS Power's response was $0.25 per month, under a customer base of 506,965. The current GRA, in PR-02 Attachment 2, shows a total estimated 2022 opt-out meter reading cost of $746,186 with a customer base of 522,142. Using simple math, this translates to a monthly customer amount of $0.12.

[432] The economic analysis provided with the AMI capital application (M08349) included a forecasted Meter Reading and Field Work Reduction cost savings totalling a present value of $56.8 million over the life of the project. Board IR-3 in Exhibit N-37 asked NS Power to provide the monthly cost reduction per customer resulting from the meter reading savings. In its response, NS Power stated that it did not do that calculation:

The AMI investment forecast savings and costs vary significantly across the project life. Collectively they constitute a relatively small portion of NS Power's annual revenue requirement approved for recovery from customers through customer rates. Consistent with this, the Company has not calculated a monthly cost reduction per customer resulting from the AMI meter reading savings.

[M08349, Exhibit N-37, Board IR-3]

7.13.2.1 Findings

[433] In considering NS Power's requested opt-out fee, the Board questions whether all reasonable options have been explored to minimize or eliminate the proposed fee. It is clear from NS Power's responses to IRs and under cross-examination that significant gaps exist in its analysis.

[434] For example, Regulation 5.1 clearly enables customers to submit meter readings via postcard, and "the Company may consider postcard meter reading to be actual meter readings". In questioning by Board Counsel, Mr. Drover stated "That is true", but asserted that reading the AMI meters is more complicated than reading the traditional meters, since they cycle through various forms of information so it can be challenging to get the exact consumption reading.

[435] Despite Mr. Drover stating that analog meters are complicated, provisions in Regulation 5.1 allow customers to take their own meter readings and send them to NS Power. In fact, NS Power's website includes a page titled "Send Your Meter Read", with an illustration on how to read the analog meter and an online form to submit the meter and account information. It is the Board's view that similar instructions can be developed for customers to read their digital meters and submit that information electronically or otherwise.

[436] In considering the requirement for an opt-out fee, the Board notes that customers who opt-out of the smart meter program will still be paying for that capital project through costs that are embedded in rates. Furthermore, the Board understands that many of the opt-out customers have done so due to their concerns about the health impact, whether proven or not, while customers on fixed- or low-income raised different concerns.

[437] Upon consideration of this issue, the Board is not persuaded that the amount of the proposed opt-out fee, or the need for a fee, has been fully explored or justified. It is incumbent upon NS Power to provide its customers with flexible options which could minimize the energy cost burden. That flexibility could include monthly, bi-monthly, semi-annual, or some other schedule of meter readings suitable for its customers.

[438] Accordingly, the Board does not approve the proposed opt-out fees at this time. NS Power may seek approval at a later time, after it has acquired actual experience with opt-out costs and has clearly demonstrated its experience with flexible customer options.

[439] Recognizing that current Regulations require monthly or bi-monthly meter readings, the Board will consider future amendments as may be appropriate.

[440] Regarding NS Power's request for approval to limit determination of the two percent threshold in Performance Standard 11 to customers with AMI meters, the Board considers that request to be premature. At this time, there is uncertainty with the number of meter readings that will be taken per year at each customer location, as well as uncertainty with what constitutes an estimated reading.

7.13.3 Large Industrial Tariff

[441] Two elements of the Large Industrial Tariff (the Interruptible Rider and the Distribution Adder) were canvassed in the evidence and addressed in the GRA Settlement Agreement [see: Exhibit N-26, PR-01 Attachment 1, pp. 35-40].

[442] The Large Industrial Interruptible Rider (LIIR) includes a credit to the electricity cost for LIIR customers who agree to accept non-firm service. The credit amount is applied to Billed Demand and is calculated based on the avoided cost of a combustion turbine, but the current credit rate (i.e., $3.43/kVA/month of billed demand) has not changed since 1996. NS Power updated the credit amount in this GRA based on current costs. The credit was proposed to change over the test years to the following amounts: $7.408/kVA/month in 2022, $7.486/kVA/month in 2023 and $7.263/kVA/month in 2024.

[443] The tariff also includes a new Distribution Adder. This charge applies to customers connected at the distribution level. In the application, the Adder increases over the test years to the following amounts: $1.570/kVA/month in 2022, $1.632/kVA/month in 2023 and $1.788/kVA/month in 2024.

[444] In the GRA Settlement Agreement, the parties agreed that the 2023 interruptible credit amount of $7.486/kVA should apply for the test years. However, they also agreed that the interruptible credit will be reviewed in the next COSS. For the Distribution Adder, the parties also agreed that the 2023 amount of $1.632/kVA should apply for the test years.

7.13.3.1 Findings

[445] The Board is satisfied that the interruptible credit should be updated because it was based on 1996 avoided costs of running a combustion turbine. The Board accepts the new calculated amount as reasonable and appropriate. As noted, the credit

will be reviewed in the next COSS. The Board also approves the addition of the new Distribution Adder and the amount as agreed to by the parties.

7.13.4 Pole Attachment Fees

[446] In its application, NS Power requested approval of an increase in the rate it charges to telecommunications carriers to attach their equipment to poles owned by NS Power (pole attachment fee). The original proposed increase represented an almost threefold jump from the current $14.15 to $37.71 per year. Various telecommunication carriers intervened in the GRA and filed evidence opposing the proposed increase, including Eastlink, Rogers and Xplore. A number of IRs were also exchanged among the parties and Rebuttal Evidence was filed. Among other issues, the telecommunications carriers identified their concerns about various assumptions used by NS Power in the calculation of the pole attachment fee.

[447] On September 16, 2022, NS Power filed a Settlement Agreement with the Board proposing a revised pole attachment fee, executed by NS Power, Eastlink, Rogers, and Xplore [Exhibit N-138]. The parties requested approval of the new proposed pole attachment fee set out as follows:

> 1. The Parties have agreed to a pole attachment rate effective the date of approval by the Board of this Settlement Agreement of $22/per pole/per year, with the rate to be increased by 2% on each of January 1, 2023 and January 1, 2024.
>
> [Exhibit N-138, p. 1]

[448] No other party in the GRA opposed the Settlement Agreement reached by NS Power with the telecommunication carriers. Indeed, in the comprehensive GRA Settlement Agreement, the parties expressly supported the terms of the pole attachment fee settlement.

[449] At the hearing, the Board asked NS Power to file an undertaking setting out the various assumptions considered by the Utility to determine that the pole attachment fee settlement was “just and reasonable” in terms of the components making up the fee to be charged to the users. NS Power noted that the reduced pole attachment fee would have an impact of about $3 million on its revenue requirement, compared to the original proposal. In response, NS Power filed Undertaking U-49 setting out its assumptions about the various components of the calculation of the fee.

[450] After the Board’s request for the Undertaking, Mr. Grant noted that the Settlement Agreement represented a negotiated compromise on a variety of the elements of the fee. Thus, the assumptions made by his clients to reach the settlement on the fee itself may not be the same as those made by NS Power. While he submitted that the agreement represented a just and reasonable resolution of the issues and should be approved, Mr. Grant said in future proceedings all parties should be free to make submissions on any aspect of the pole attachment fee. Accordingly, his client carriers and NS Power proposed the following stipulation for the Board’s consideration of the Settlement Agreement on this matter:

> NSPI and the carrier group negotiated the Settlement Agreement, Exhibit N-138, Pole Attachment Fee, as a total rate. It arrived at the $22 per pole as a compromise of their respective positions. The parties did not negotiate or agree upon the cost-of-service components to justify the $22 compromise rate. For example, there was no agreement on the appropriate pole attachment ratio. [Undertaking] U-49 therefore would represent NSPl's view of the - - of a cost-of-service justification for the Settlement Agreement rate of $22.
>
> [Transcript, September 21, 2022, pp. 2131-2132]

[451] In their Closing Brief, Mr. Grant and Ms. Milton submitted that the pole attachment fee set out in the Settlement Agreement should be approved by the Board:

> 21. In the present proceeding, NSPI and the Carrier Group have engaged extensively and intensively in the prehearing procedures to examine and test the evidence regarding the Pole Attachment Fee. Other parties have had similar opportunities. NSPI and the Carrier Group have succeeded in reaching a settlement agreement that reflects a

compromise of their positions based upon their evidence. We submit the Settlement Agreement is properly supported. It is an outcome that was within the range of reasonable outcomes the Board could have reached on the evidence and, particularly in the absence of any opposition, represents a success of the regulatory process.

22. In its initial evidence in this proceeding, NSPI requested an increase in its Pole Attachment Fee from $14.14 to $37.71. The Carrier Group provided detailed evidence recommending a Pole Attachment Fee of between $14.90 and $19.27.

…

25. The settlement rate is a compromise and is not based on agreement on specific cost inputs to the Pole Attachment Fee. NSPI has submitted a cost of service justification for a pole attachment rate of $21.81. While the Carrier Group does not agree with some of the cost of service inputs used by NSPI, including use of a pole attachment ratio of less than 2, the Carrier Group believes that the $22 rate represents a reasonable compromise based on the application of the same methodology established in the 2002 Decision using available cost of service information. The $22 rate is also a significant increase in the Pole Attachment Fee, resulting in incremental revenue to NSPI at no additional cost. [Emphasis added]

[Eastlink/Rogers/Xplore Closing Brief, pp. 5-7]

7.13.4.1 Findings

[452] Earlier in this decision, the Board outlined the principles it applies in its review of settlement agreements. Those principles apply equally to the Board's review of the Settlement Agreement about the pole attachment fee. The agreement garnered the support of all parties directly impacted by the pole attachment fee and represents an all-encompassing resolution of the various issues, in the form of a proposed fee, raised by the telecommunications carriers.

[453] The Board observes that no other party in this matter challenged the Settlement Agreement, including the revised pole attachment fee. The current fee has been in effect since 2002 and it is appropriate that the inputs to the calculation be updated, at least to the extent that it informs the range of possible outcomes for the fee. The Board is also satisfied that, considered as a whole, the revised pole attachment fee represents a fair and reasonable estimate of what the amount should be, taking into account the

various issues which were in dispute between NS Power and the pole attachment customers.

[454] Having reviewed the Settlement Agreement about the pole attachment fee, and the submissions, the Board finds that the revised pole attachment fee is just and reasonable. The Board approves the pole attachment fee of $22/per pole/per year, with the rate to be increased by 2% on each of January 1, 2023, and January 1, 2024. The adjusted rates for each of the test years are to be confirmed in the compliance filing.

7.13.5 Open Access Transmission Tariff Charges

[455] In this GRA, NS Power is requesting approval of the revenue requirement and updated prices for services offered under the OATT. The OATT includes terms, conditions and rates for Transmission Services and Ancillary Services, as well as service and 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.

[456] Parties to the GRA Settlement Agreement have agreed to the following terms regarding the OATT:

> …the Rates for Services in NS Power's Open Access Transmission Tariff shall be capped at a maximum increase of 1.8% in 2023 and 0% in 2024. With respect to the CBAS recommendations proposed by WKM Energy Consultants, the parties agree that these issues will be left to the Board's determination in this proceeding. The MEUs will file a closing argument on these issues, following which NS Power and other parties as they see fit will have the opportunity to file a reply.
>
> [Exhibit N-155, p. 6]

[457] In their Closing Submission, the MEUs noted their support for Board approval of the GRA Settlement Agreement but also sought Board approval of the

Capacity Based Ancillary Services (CBAS) recommendations proposed by its consultant, Mr. Marshall:

> … As a signatory to the Settlement Agreement, the MEUs support the Board's approval of the Settlement Agreement as filed. The following points in the Settlement Agreement are critical from the perspective of the MEUs:
>
> - Confirmation that the Rates for Services in NS Power's Open Access Transmission Tariff shall be capped at a maximum of 1.8% in 2023 and 0% in 2024;
>
> …
>
> Since these issues are of significant importance to the MEUs and have long-term implications for the rates to be charged as part of the competitive wholesale market in Nova Scotia, the MEUs sought and obtained agreement from all signatories to the Settlement Agreement that the Backup/Top-up ("BUTU") GHG credit as proposed by Mr. Dominie and the Capacity Based Ancillary Services ("CBAS") recommendations proposed by Mr. Marshall would be left to the Board's determination in this proceeding following closing argument and reply.
>
> [MEUs Closing Submission, pp. 1-2]

7.13.5.1 Findings

[458] The Board approves capping NS Power's OATT rates at a maximum increase of 1.8% in 2023 and 0% in 2024 as described in the GRA Settlement Agreement.

7.13.6 Capacity Based Ancillary Services

[459] Ancillary Services are the support services that are required to enable the Transmission System to transmit energy while maintaining reliable operation of the system. They range from the actions necessary to effect and balance a transfer of electricity between buyer and seller, to services that are necessary to maintain the integrity of the Transmission System and enable it to be operated reliably at design voltages and frequency.

[460] The capacity based ancillary services provided from generation capacity must be committed to the provision of the service and cannot be used at the same time

for other purposes. The costs of supplying these services are calculated from the embedded costs of existing generating units and the revenue requirement is determined by multiplying the per-unit embedded cost of capacity for each service by the amount of capacity required to deliver the service.

[461] NS Power is the Transmission Provider and operates in accordance with North American Electric Reliability Corporation (NERC) Reliability Standards and Northeast Power Coordinating Council (NPCC) criteria as approved by the Board. Its responsibility includes determining the need and procurement of sufficient ancillary resources to reliably operate the electrical network. It is also required to make all ancillary services available to all transmission customers. Those customers can purchase capacity based ancillary services from the Transmission Provider, or from a third party, or they can self-supply.

[462] In this application, NS Power requested Board approval of the following revenue requirements and rates for capacity based ancillary services:

Figure 2-8 Revenue Requirement of Capacity Based Ancillary Services

Revenue Requirement of Capacity Based Ancillary Services									
Services	Revenue Requirement ($/kW-yr)			Services Required (MW)			Revenue Requirement ($1000/yr)		
	2022	2023	2024	2022	2023	2024	2022	2023	2024
Regulation	132.0	147.5	153.3	32.0	32.0	32.0	4,224.4	4,720.4	4,904.6
Load Following	170.0	181.2	184.4	176.0	176.0	176.0	29,917.7	31,886.2	32,459.4
Spinning (10-minute)	135.0	140.3	139.5	32.0	32.0	32.0	4,319.3	4,489.8	4,463.6
Supplemental (10-minute)	98.4	125.9	141.8	136.0	136.0	136.0	13,383.9	17,123.9	19,288.4
Supplemental (30-minute)	155.2	152.9	147.3	50.0	50.0	50.0	7,758.2	7,645.6	7,365.4

Figure 2-9 Rates for Capacity Based Ancillary Services

Rates for Capacity Based Ancillary Services			
Services	Rate ($/MW – month)		
	2022	2023	2024
Regulation	195.8	218.9	226.8
Load Following	1,386.6	1,478.7	1,501.1
Operating Reserve – Spinning	200.2	208.2	206.4
Operating Reserve – Supplemental (10 minute)	620.3	794.1	892.0
Operating Reserve – Supplemental (30 minute)	359.6	354.6	340.6

[Exhibit N-18, SR-01 Attachment 1e, pp. 19-20 of 32]

[463] As noted above, the GRA Settlement Agreement limits the OATT rates to a maximum increase of 1.8% in 2023 and 0% in 2024.

[464] Based on his review of NS Power's evidence, the MEUs' consultant determined that NS Power's approach significantly overstated the costs required for CBAS. In his evidence, Mr. Marshall described the issues contributing to that overstatement and provided his estimation of 2022 rates for the five CBAS items:

> The increases in OATT rates proposed by NS Power are substantive with increases from current rates ranging from 5% to 168% by 2024. WKM proposed CBAS rates for 2022 are close to current rates for Load Following and Spinning Reserve, an increase for 10-Minute Supplemental Reserve and reductions for AGC and 30-Minute Supplemental Reserve.

NS Power and WKM Proposed Rates Compared to Current OATT Rates ($/MW-month)								
		Transmission		CBAS				
		Point to Point	Network Service	AGC	Load Following	Spinning Reserve	10-Min Reserve	30-Min Reserve
Current	1	4,990	4,241	217	777	166	332	281
NSP proposed								
2022	2	4,682	4,257	196	1,386	200	620	359
2023	3	5,766	5,257	219	1,479	208	794	354
2024	4	6,986	6,340	227	1501	206	891	340
Increase	5=(4-1)/1	**40%**	**49%**	**5%**	**93%**	**24%**	**168%**	**21%**
WKM Proposed								
2022	6			147	732	167	389	143
Increase	7=(6-1)/1			**-32%**	**-6%**	**1%**	**17%**	**-49%**

[Exhibit N-54, p. 24]

[465] In his Opening Statement, Mr. Marshall explained his concerns with the assumptions NS Power used to determine its proposed CBAS rates. His recommendations were repeated in the MEUs Closing Submission:

> 1. **ELIADC Load** – “The ELIADC load is a valuable resource for NS Power. Its contributions to Spinning Reserve, 10 and 30-minute Supplemental Reserves, and Load Following should be included in the costing of those services as recommended in my Evidence.” (para. 8 of Ex. N-117)
>
> 2. **AGC Revenue Requirement** – “The current NS Power proposal for Schedule 3(a) (Regulation) is based on an AGC requirement of +/- 16 MW for a total of 32 MW total done through a statistical analysis of NS Power net loads. Including the -16 MW component in the calculation is discriminatory and over charges wholesale market participants for AGC. The Revenue Requirement for Schedule 3(a) should be calculated using only the +16 MW component.” (para. 17 of Ex. N-117)
>
> 3. **Load Following Requirement** – “In its Rebuttal, NS Power has redone the analysis for 2021 data and determined a new requirement of 165 MW, which continues to rely on a three standard deviation method. I continue to consider this excessive in the circumstances. I recommend the two standard deviation value of 114.6 MW be used for ratemaking purposes, as it reflects what NS Power states it will require for operational purposes and remains significantly higher than the comparable requirement for NB Power.” (para. 21 of Ex. N-117)
>
> 4. **Over Crediting of Wreck Cove in 10-minute spinning reserve costs** – “The correction of Wreck Cove over-credit provided in Paragraph 46 of my Evidence results in a reduction to 10-minute spinning reserve costs and should be required by the Board. Charging the costs associated with Wreck Coves full load toward 10-Minute spinning reserve is not appropriate.” (para. 24 of Ex. N-117)
>
> 5. **Inclusion of CTs in costing of 30-minute supplemental reserve** – “I agree that slower ramping on-line generation can provide 30-minute reserve if it is available. However, in winter with high loads and low wind conditions the only resources that may be available are the CTs. The CTs should be included in the costing of 30-minute supplemental reserve as noted in Section X of my evidence.” (para. 26 of Ex. N-117)
>
> [MEUs Closing Submission, pp. 10-11]

[466] The MEUs’ Closing Submission stated that the Board should accept these recommendations and they should be used the next time NS Power applies for approval of CBAS rates. The MEUs also recommended that NS Power collaborate with Mr. Marshall to obtain information from NPCC about the terms under which New Brunswick’s 100 MW of interruptible load is counted toward reserves. That collaboration should address the way interruptible load in Nova Scotia, including the ELIADC load, could be

counted toward reserves, so that such information is available as part of NS Power's next application for approval of CBAS rates.

[467] The MEUs concluded their Closing Submission by stating their concern about NS Power's dominant position in the market:

> The MEUs are and remain particularly concerned that NS Power not be permitted to use its dominant position as the incumbent utility to recover excess costs from wholesale market customers in the competitive market in Nova Scotia.
>
> [MEUs Closing Submission, p. 21]

[468] NS Power did not accept any of those recommendations and expanded on its reasoning in its Reply Submission.

ELIADC Load

[469] Regarding its treatment of the Extra Large Industrial Active Demand Control (ELIADC) load, NS Power provided the following explanation:

> The ELIADC load is optimized along with other supply resources in the development of the day-ahead dispatch plan, providing the least cost dispatch of energy and ancillary services for customers. Scheduling of ELIADC load for the sole purpose of ancillary services would not provide the intended benefits of the rate.
>
> In the development of the day-ahead plan, during hours when the margin between generation plus reserve and load is small, PHP load will be economically dispatched down and therefore be unavailable for Operating Reserve.
>
> … on days when Port Hawkesbury Paper load is not already dispatched down, if the load is available, Nova Scotia Power will use ELIADC in real-time to dispatch PHP load as operating reserves after all other generation reserves are utilized. Currently, this is not the typical operating circumstance, and as such, should not be reflected in the CBAS pricing.
>
> [NS Power Reply Submission, p. 32]

Automatic Generation Control (AGC) Revenue Requirement

[470] On the AGC issue, NS Power stated:

> NS Power commits generation capacity to serve both the +16 MW (RegUp) and the -16 MW (RegDown) components of Regulation service. This capacity is committed in addition to that required to serve load, so the costing for the total of 32 MW of Regulation service is

> included in the calculation for the Regulation service rate. With the high level of wind generation as a percentage of total generation, NS Power requires this level of Regulation service to properly balance the system.
>
> [NS Power Reply Submission, pp. 34]

Load Following Requirement

[471] In addressing Mr. Marshall's recommendation that a 2-standard deviation should be used to determine the CBAS rate associated with the load following issue, NS Power stated:

> Mr. Drover's opening statement includes the following:
>
> > Regarding the load following requirements and the use of a 2 standard deviation analysis versus the 3 standard deviations, Nova Scotia Power believes the analysis that it has completed is more appropriate as it is more comprehensive in the distribution samples that it covers, and it is based on Nova Scotia Power historical load patterns. The three standard deviation approach covers 99.7 percent of normal distribution, which is virtually all samples, whereas the two standard deviation approach only covers 95 percent of the distribution samples. With the variability of the large amount of wind on the system during any given day, and how quickly that can change, the more robust analysis of load following requirements provided by three standard deviations is necessary.
>
> Judgement is required in matters such as this and the views of parties may reasonably differ. For a utility transitioning to higher levels of variable renewable generation as NS Power continues to do, with a penetration of wind which has been confirmed by Mr. Marshall to be greater than that of NB Power, the Board should accept the established practice in Nova Scotia and reject Mr. Marshall's recommendation.
>
> [NS Power Reply Submission, p. 35]

[472] During the hearing, the Board also questioned NS Power regarding its rationale in using the 3-standard deviation versus the 2-standard deviation methodology:

> **Q.** So in terms of the difference between the two methodologies, to me it sounds, at the high end, if that's in fact what you're concerned about, it's really only 2.5 percent difference.
>
> **A.** (Drover) Looking at it that way, that is -- that's right.
>
> **Q.** So really, I guess -- and I understand where you're coming from with the variability and whatnot, but I guess for two and a half percent, is Nova Scotia Power being overly conservative using that three standard deviation methodology?

> **A.** (Drover) Again, I don't think so. Because of the way that we have approached in the past using our historical methods and looking at our systems, I do think that that 2.5 percent is important. And to be honest, there is so much variability, to go to the two standard deviations, I would worry that we would not cover all the variability.
>
> **Q.** Okay. Do you agree with Mr. Marshall's numbers, though, if, in fact, the two standard deviation methodology was used that the load filing [following] requirement would be roughly 115 megawatts?
>
> **A.** (Drover) We didn't do that analysis. We only did the three standard deviation analysis. I agree that's what he presented, but I haven't done that myself.
>
> [Transcript, September 21, 2022, pp. 2046-2047]

Over Crediting of Wreck Cove in 10-minute spinning reserve costs

[473] In his response to Mr. Marshall's Opening Statement, Mr. Drover disagreed with Mr. Marshall's suggestion that Wreck Cove was being over-credited for spinning reserves. This was repeated in NS Power's Reply Submission:

> Mr. Drover's opening statement provides:
>
> > Regarding Mr. Marshall's claims that Wreck Cove is being over-credited for spinning reserves and the combustion turbines not being considered for 30- minute reserve, Nova Scotia Power disagrees with both statements. As stated in the Nova Scotia Power rebuttal evidence, both Wreck Cove units have the ability to ramp up to full load fast enough to be considered for both spinning reserve and 10-minute reserves, which is how the units are utilized, and therefore are not overstated, but used for both operating reserve calculations.
>
> The Company's development of CBAS charges reflects the actual use of the associated assets on the NS Power system. No adjustments to account for Mr. Marshall's conflicting views are required.
>
> [NS Power Reply Submission, p. 36]

[474] On this topic, NS Power's Rebuttal Evidence stated that Wreck Cove will not be artificially capped in providing spinning reserve capacity. During the hearing, the Board requested clarification of that statement:

> **Q.** So there's a bit of discussion about this, but there's a comment there that Nova Scotia Power makes about Wreck Cove, and it says that "it will not be artificially capped in providing spinning reserve."
>
> I'm wondering if you could explain what is meant by "artificially capped".

A. (Drover) So spinning reserve is a function of 10-minute reserve. Our 10-minute reserve requirement in totality is 168 megawatts, which is the size of our larger single contingency, which is Point Aconi.

Spinning reserve is a component of that, which is 32 megawatts. What we were trying to illustrate there is that Wreck Cove, with its fast-acting generation and its ability to ramp up quickly, should be counted as both, but not double counted. So 32 megawatts of Wreck Cove's ability would be for spinning reserve, and then the remaining reserves that it has available would [be] in the 10-minute reserve.

Q. And how did you see Mr. Marshall's proposal or suggestion on this point as artificially capping Wreck Cove?

A. (Drover) The way we viewed it was that there was less than 32 megawatts of spinning reserve that was included in his calculation, where we were saying that the full 32 could be used for spinning.

[Transcript, September 21, 2022, pp. 2116-2117]

Inclusion of Combustion Turbines (CTs) in costing of 30-minute supplemental reserve

[475] Regarding 30-minute supplemental reserve costs, Mr. Marshall’s evidence suggested that NS Power omitted using less expensive CTs for that reserve requirement:

93. The $/kW-yr cost for the 30-Minute Supplemental Reserve for 2022 is determined in Table E4-7 of Attachment 1 in NSPI (MUNIS) IR-41 as $152.91/kW-yr. It is multiplied by the 50 MW obligation to determine a Revenue Requirement for 10-Minute Supplemental Reserve equal to $7,645,500 for 2022.

94. WKM agrees that 50 MW is the correct obligation of NS Power for 30-Minute Supplemental Reserve but disagrees with the $152.91/kW-yr cost as NS Power does not include available CT capacity in Table E4-7 calculation of cost. It only includes thermal coal units and the oil and gas units at Tufts Cove.

[Exhibit N-54, p. 21]

[476] In addressing this concern, NS Power stated that the CTs do contribute to 30-minute supplemental reserve after their contribution to 10-minute reserve requirements, but their 30-minute contribution is negligible:

…All of the Combustion Turbines are also fast acting generation units and primarily contribute to 10-minute non-spinning reserve before 30-minute reserve. The number of hours that the CTs are operating for capacity and therefore contribute to overall system 30-minute reserve is negligible. This approach ensures that the Wreck Cove units and the CTs are properly accounted for in Spinning Reserves, 10-minute reserves and 30-minute reserves without being double counted.

[Exhibit N-142, pp. 4-5]

[477] In its Reply Submission, NS Power stated:

> While under some circumstances CTs can contribute to 30-minute operating reserves, it is more appropriate to assess the use of generation resources considering their intended use within the overall portfolio for the provision of energy and ancillary services. In this context, CTs are fast acting generation resources which are used to support 10-minute reserve requirements. Likewise, coal, gas, and heavy fuel oil fired generation resources tend to be slow to respond and are used to support 30-minute reserve requirements.
>
> The capacity available from fast-acting CTs may at times exceed the 10-minute operating reserve requirements; however, like all generators in the fleet, CTs are subject to planned maintenance outages, forced outages, de-ratings, reassignment for other purposes such as voltage support, and transmission constraints which may limit their output. Based on a portfolio view of the generation fleet, the assignment of CT costs to the provision of capacity based ancillary services for providing 10-minute operating reserves is appropriate.
>
> [NS Power Reply Submission, pp. 37-38]

7.13.6.1 Findings

[478] As stated earlier, the MEUs' Closing Submission noted their support for Board approval of the GRA Settlement Agreement, but also sought Board approval of the CBAS recommendations proposed by Mr. Marshall. In addition, they stated that the Board should accept these recommendations and they should be used the next time NS Power requests approval of CBAS rates. The MEUs also recommended that NS Power obtain information from NPCC about the terms under which interruptible load is counted toward reserves. In its response in Undertaking U-14, NS Power stated that interruptible load is counted toward 10-minute reserve when the required amount is not available from generation resources. It also stated that planning to interrupt interruptible loads is not a consideration in meeting day-ahead load and reserve requirements. The Board considers there may be some value in alternate treatment of interruptible loads and directs NS Power to explore options with NPCC. In the next GRA, NS Power is directed to file its analysis of cost implications associated with alternative treatment of interruptible loads.

[479] In these findings, the Board addresses each of the five recommendations included in the MEUs' Closing Submission.

[480] The Board understands the unique nature of the ELIADC tariff developed with the intention of benefitting PHP, as well as the broader NS Power customer base. Although the PHP load could be used to address spinning or supplemental reserve requirements, the Board accepts NS Power's position that scheduling ELIADC load for the sole purpose of ancillary services would not provide the intended benefits of the rate. Recognizing that the tariff is limited in its term and is due for review prior to the end of 2023, parties may choose to make further submissions on this issue when that tariff is being reviewed, or during the COSS, or during the next GRA.

[481] On the AGC issue and NS Power's treatment of the -16 MW requirement in its CBAS calculation, the Board views Mr. Marshall's concern worthy of further consideration. The Board notes Mr. Marshall's reference in Exhibit N-117 to FERC Order 890, paragraph 690, which was quoted as:

> *"If the transmission provider elects to have separate demand charges assigned to customers for the purpose of recovering the cost of holding additional reserves for meeting imbalances, the transmission provider should file a rate schedule* ***and demonstrate that these charges do not allow for double recovery of such costs****."*

[482] Prior to the next GRA, NS Power is directed to explore alternative treatment of the -16 MW requirement and to demonstrate that it is not double charging transmission customers.

[483] The load following costing issue focuses on whether the 2-standard deviation or the 3-standard deviation methodology should be applied in determining the associated CBAS rate. In considering this question, the Board notes the following

statements contained in NS Power Control Centre Operations documentation, provided as Attachment 2 in NS Power's response to Munis IR-39:

> For ratemaking purposes, 3-sigma analysis is typically used, providing for 99.7% of samples.
>
> …
>
> Operationally, net load variations would be managed through the day-ahead schedule, but it would reasonable expected [sic] that 2-sigma or 95% probability of variation would be required.
>
> [Exhibit N-39, Attachment 2, p. 5]

[484] The Board is not persuaded that NS Power has sufficiently justified the higher cost or the need to apply a 99.7% probability in the load following CBAS rate calculation. NS Power is directed to apply the 2-standard deviation methodology in this CBAS calculation when submitting its compliance filing.

[485] Regarding the suggestion that Wreck Cove capacity may be over-credited in the 10-minute spinning reserve costs calculation, the Board understands NS Power's evidence to be that the units are utilized for spinning reserve and for 10-minute supplementary reserve, so the CBAS charges reflect that actual use of those assets. However, considering Mr. Marshall's questioning of the calculation, NS Power is directed to clearly demonstrate, no later than in its next GRA, how the spinning reserve and 10-minute supplementary reserve utilization is represented in its calculations.

[486] Regarding inclusion of less expensive CTs in the CBAS costing calculations for 30-minute supplemental reserve, the Board understands NS Power's evidence to be that the CT contribution to that reserve capacity is negligible, so it is not factored into the calculation. Considering that there are currently seven units in service, the Board finds NS Power's explanation to be lacking and directs that a more fulsome explanation be provided, no later than in its next GRA, to justify its position in this matter.

7.13.7 Other Tariffs and Regulations

[487] In its application, NS Power also applied for changes to Regulation 7 of its Board-approved Regulations, which sets out miscellaneous charges for various services provided by the Utility to its customers. These included: 7.1 Schedule of Charges; 7.2 Schedule of Wiring Charges; and 7.3 Schedule of Load Research Monitoring, Reporting and Analytical Charges. NS Power reviewed these charges in light of changes in service delivery, cost structure, and technological advances. For many of the charges, the implementation of remotely-read AMI meters has caused the charges to decrease, reflecting the savings achieved by performing connections, disconnections and meter readings from a central office, instead of dispatching technicians to customer sites. Revisions to Regulation 7.1 include: the separation of connection and disconnection charges into different rates for customers with remotely-read meters and non-remotely read meters; the addition of non-standard meter reading charges; and the removal of the rates associated with the discontinued Mobile Radio Network access service.

[488] The Board notes there were also proposed revisions to the Distribution Tariff as well as other tariff revisions required to implement the Storm Rider and DSM Rider.

[489] In the GRA Settlement Agreement, the parties agreed with all other proposed revisions to NS Power's tariffs and miscellaneous charges in the Regulations, except as noted in the settlement (i.e., Pole Attachment Fee, OATT, and CBAS, which are also discussed elsewhere in this decision). Further, the Board notes that, elsewhere in this decision, it has made findings about the AMI opt-out fee, CBAS and the MEUs' requested BUTU GHG credit.

7.13.7.1 Findings

[490] Subject to the Board's findings elsewhere in this decision, and NS Power providing its compliance filing, the Board approves the proposed changes to the miscellaneous charges in Regulation 7 and the proposed revisions to the various tariffs, including the Distribution Tariff.

7.13.8 BUTU GHG Credit

[491] The MEUs asked the Board to establish a credit in the embedded cost calculation for NS Power's Backup and Top-up (BUTU) Tariff for the reduction in GHG compliance costs to NS Power due to the movement of portions of their load to third party suppliers. The MEUs noted that the shifting of this load from NS Power's system reduced the RES-eligible energy NS Power must acquire and freed up emissions cap room that would be used for the benefit of other customer classes to reduce GHG and sulfur dioxide compliance costs.

[492] The MEUs submit that since these benefits are the direct result of their removal of their load from the NS Power system, they should be provided "solely to the customer class whose actions have created this benefit" and not socialized to the benefit of all customers. The MEUs said this would be like the interruptible credit available to large industrial customers who have agreed that service to them may be interrupted in times of high demand.

[493] In its Rebuttal Evidence, NS Power challenged the analogy to the credit provided through the Large Industrial Interruptible Rider:

> The LIIR credit relates to a distinct difference in service taken by the LIIR customers (non-firm service) versus firm service customers (including BUTU customers) and the associated long-term savings this conveys to other customers. The long-term capacity

> savings are distinct and reasonably quantifiable (the cost of a combustion turbine). The MUNIS have opted out of bundled service entirely. The decision to opt for competitive supply is presumably taken for the financial benefits it provides to the MUNIS. The decision to take BUTU service from NS Power is presumably because this is the low-cost BUTU service option available. Unlike the Large Industrial Interruptible customers, the MUNIS are not taking a lesser form of service and this is not tied to a GHG benefit or any other emission benefit (or cost) that could accrue to bundled service customers.
>
> [Exhibit N-102, p. 147]

[494] In their Closing Submission, the MEUs disagreed with these assertions and said they were also taking a lesser form of service under the BUTU Tariff because they were significantly reducing the energy requirements being placed on NS Power's system. They noted that this reduction was directly tied to a GHG benefit that currently accrued to bundled service customers "as each MWh of reduction in load reduces the marginal cost of GHG compliance that is otherwise borne by the overall system."

[495] The MEUs also emphasized they were not seeking a credit for simply departing NS Power's system or reducing their consumption. Rather, they submitted that the proposed credit was integral to proper pricing under the BUTU Tariff. They also noted that if they do not use the BUTU Tariff, they will not receive any form of credit under their proposed approach. The MEUs accept that if "the customers leave the system or reduce load but do not take service under the BUTU Tariff … no credit would be applicable or otherwise paid to the MEUs."

[496] In its Reply Submission, NS Power further contrasted the proposed credit under the BUTU Tariff with the Large Industrial Interruptible Rider credit. NS Power also noted that taking BUTU service from NS Power is not mandatory in the wholesale market and that if the MEUs are able to acquire backup service of firm supply from another source, they are free to do so.

[497] NRR supported the proposed GHG credit for the BUTU Tariff in its Closing Submission. NRR submitted that the provisions under the *Electricity Act* and the *Renewable Electricity Regulations* establishing a wholesale market for the MEUs were intended to provide them with access to new competitive opportunities and increase the amount of renewable energy on the system. NRR said the credit recognized the value provided by the MEUs' actions in participating in the competitive market and directly reducing provincial GHG emissions on a go-forward basis. The MEUs relied on these comments in their Reply Submission.

[498] The only other parties to address this issue were the Industrial Group and Dalhousie University in their Reply Submission. They noted that the MEUs already reduce their contribution to fixed costs by removing their load from NS Power's system and that these costs are paid by above-the-line customers. They submitted that this "negotiated concession to the MEU's during the development of the OATT whereby they are not responsible for the payment of exit fees should be considered before considering crediting the MEU's from leaving the system."

[499] Having said that, the Industrial Group and Dalhousie University noted that the GRA Settlement Agreement requires a consultative process for a new cost of service study which would provide an opportunity to comprehensively review the cost inputs of the BUTU Tariff at the same time as cost inputs for bundled services to determine if there is any "cross-subsidization" in the absence of the requested credit. They submitted the Board should not approve a stand-alone GHG credit in this proceeding.

7.13.8.1 Findings

[500] The Board agrees that if a credit were to be considered for the MEUs to account for any system benefits relating to GHG compliance costs, any incremental benefits associated with the removal of the MEUs' load from the NS Power system should be offset by incremental costs associated with the removal of that load. Additionally, as NS Power points out in its Reply Submission, the administration of the credit may result in administrative costs that would also have to be considered. However, the Board concludes there should not be any credit, so this does not need to be addressed.

[501] The Board disagrees that the claimed credit is comparable to the Large Industrial Interruptible Rider. First, the Board accepts NS Power's position that interruptible service is a lesser form of service compared to firm service. Second, the Interruptible Rider was designed specifically to avoid having to build additional capacity on the system. In other words, the rate was specifically designed to produce the system benefit for which those on the rider are being compensated.

[502] In contrast, if there is any GHG compliance system benefit arising from the BUTU Tariff, it is ancillary to the main purpose of the tariff. The BUTU Tariff was not designed with the main objective of producing that result. It was designed to benefit the MEUs.

[503] The BUTU Tariff was not part of the original development of the OATT that was approved by the Board in 2005. It is not a required tariff under the *Electricity Act* and was developed later to support or enable the MEUs to access a competitive supply of electricity at their request, as was noted by the Board in its decision approving the BUTU Tariff in 2009:

[3] NSPI, in its prefiled evidence, provided both a summary of events leading up to this application and the application:

> On February 1, 2007 the *Electricity Act* came into effect, opening the Nova Scotia electricity market for wholesale competition. NSPI's Municipal class customers are eligible, at their option, to take some or all of their electric energy requirements from a supplier other than NSPI. To date, none of these customers have selected this option, and they have requested that additional tariffs applicable to the wholesale market, namely "backup, top-up and spill rates" be developed and offered by NSPI.
>
> In March 2007, after discussions with Municipal class customers and renewable energy stakeholders, the Government of Nova Scotia requested that these rates be developed and brought forward for NSUARB approval. Since that time, NSPI has worked with stakeholders to reach common understanding of the needs of these customers, the potential effects on other customers, and to subsequently prepare an application for Board approval of new tariffs.
>
> On September 12, 2007, NSPI, wholesale Municipal class customer representatives, Suez Renewable Energy North America (SRENA, a wind energy producer being considered by the Municipal utilities), Scotia Investments (the landowner of the proposed wind farm), NSUARB staff and N.S. Department of Energy (NSDoE) staff began a series of meetings to discuss the issues. Subsequent meetings of this group, or subsets as agreed to by the larger group, were held on September 28, October 10, October 18, November 16, December 5, 2007, and February 21, April 10 and April 24, 2008.
>
> These collaborative meetings helped to clarify the issues and increase the understanding of all involved. The Company and stakeholders were able to reach agreement in a number of areas and have agreed to present their individual perspectives to the UARB on any remaining issues.
>
> This application presents NSPI's proposed rates for backup, top-up and spill services. Consistent with regulation in Nova Scotia, the proposed rates are based on sound costing principles and are fair to all customers. The proposed backup and top-up tariffs are limited to Municipal class customers who are participating in the electricity market for wholesale competition under the *Electricity Act* S.N.S., 2004 c.25. NSPI requests that the Board approve the tariff designs utilized in this application only for use by this limited group of customers. Because the cost of supplying various amounts of incremental demand may differ from marginal cost (which relates to very small demand variance), applying a marginal-cost based pricing approach to larger amounts of load can come with serious financial risk.

> The spill tariff is available to third party non-dispatchable generators serving participating Municipal customers' load.
>
> [*Re Nova Scotia Power Incorporated*, 2009 NSUARB 1, para. 3]

[504] The Board also noted in that decision that service under the BUTU Tariff was voluntary, and it was contemplated at the time that other providers might also supply these services in the future:

> [17] NSPI initiated the process leading to these rates at the request of the Province of Nova Scotia and the municipal utilities. The municipal utilities wish to purchase some or all of their power and energy requirements from a non-regulated supplier, other than NSPI, as is contemplated by the *Electricity Act*. During the early transition, at least, they require a back-stopping arrangement be in place which facilitates their ability to transfer to another supplier, yet at the same time ensure their customers reliable service. As the wholesale market matures there may well be a sufficient number and diversity of independent suppliers, that this service by NSPI may no longer be needed. As was pointed out repeatedly in the hearing, it is open to the municipal utilities to take this service or not, as their needs require. If, as the market evolves, companies such as CBEX can supply these services at a price more favourable than NSPI, while meeting the municipal utilities' reliability needs, then the municipal utilities are obviously free to contract with companies other than NSPI.
>
> [*Re Nova Scotia Power Incorporated*, 2009 NSUARB 1, para. 17]

[505] Additionally, if the MEUs removed their load from the system and took no service of any nature from NS Power, the same potential for GHG compliance benefits to the system would exist. In such a case, the MEUs concede that no credit would be applicable or paid to them. In the Board's view, the MEUs should not be entitled to a credit simply because they have elected to take service under the BUTU Tariff to meet their own specific needs and requirements when they would not receive one otherwise. Furthermore, the BUTU Tariff is available once the MEUs have removed their load (or part of it) from the NS Power system. If there are any GHG compliance benefits, they arise from the election to remove load from the system and take it from another supplier.

[506] The BUTU Tariff does not remove any load from the NS Power system. It provides a backup and top-up service for load that has been removed. It is an optional service, and it may also be supplied by another provider. Although the Board is not aware

that there are any other suppliers for this service in the market, it was contemplated that as the market evolved this could occur. If NS Power's embedded cost of service were to be reduced by a credit for GHG compliance benefits, this could make the materialization of competitive sources for this service in the market even more unlikely as the cost to compete would be that much lower.

[507] Ultimately, the Board disagrees that the change to an embedded cost of service methodology for the BUTU Tariff leads inevitably to the need to provide a credit for any incidental incremental benefits to the NS Power system. To the extent that there are any, these benefits will flow through NS Power's cost of service and reduce the embedded costs in all customer rates, including the BUTU Tariff. In the circumstances the Board finds this is appropriate.

8.0 SUMMARY OF MAJOR FINDINGS AND DIRECTIVES

[508] The Board has approved most of the components of the GRA Settlement Agreement including:

- An average rate increase across all customer classes of 6.9% (including fuel and non-fuel costs) in each of 2023 and 2024;
- 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 increases from 37.5% to 40.0%;
- Agreeing in principle to the establishment of a Decarbonization Deferral Account to address the retirement of coal plants and related decommissioning costs, subject to a further consultative process;
- Implementing a Storm Cost Recovery Rider for a three-year trial period, and a DSM Cost Recovery Rider;

- Conducting an updated Cost of Service Study and Line Loss Study before the next GRA or by December 31, 2025, whichever is sooner, subject to stakeholder engagement;

- Applying a 25% reduction to the proposed increase to the 2023 customer charges;

- Increasing the credit amount in the Large Industrial Interruptible Rider; and

- Capping the Open Access Transmission Tariff at a maximum increase of 1.8% in 2023 and 0% in 2024.

[509] The Board has not approved three items in the GRA Settlement Agreement:

- The proposed AMI opt-out fee;

- The regulatory amortization of the Annapolis Tidal Generation Facility, which is to remain in rate base; and

- The inclusion of the four Maritime Link transmission capital projects in rate base, at this time.

[510] The Board has also approved a Settlement Agreement between NS Power and the telecommunications carriers, which included a negotiated settlement of the Pole Attachment Fee.

[511] The Board has denied the Municipal Electric Utilities' request for a Wholesale Market Backup/Top-up (BUTU) Tariff GHG credit. However, the Board has accepted one of their recommendations for Capacity Based Ancillary Services, and directed a review of their other recommendations.

[512] NS Power is directed to:

- Submit annual reports on April 1, 2024-2026, summarizing actual storm restoration costs for each year of the Storm Rider trial period; [para. 332]

- Include full detail on all storm restoration, storm hardening and vegetation management costs in each Storm Rider cost recovery application submitted during the three-year trial period. Also, NS Power is to engage with stakeholders to determine the specifics for how this information is to be presented, in advance of the first Storm Rider cost recovery application; [para. 338]

- 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; [para. 340]

- File an update about a DSM true-up for prior period variances no later than the first application to adjust the DSM Rider approved in this decision; [para. 359]

- File semi-annual progress reports about the stakeholder engagement process for the Cost of Service and Line Loss Studies, starting January 31, 2024; [para. 367]

- File a depreciation study before its next GRA and include the scope of the depreciation study as part of its DDA consultative process with stakeholders and the resulting report on that process; [para. 374]

- Exclude all Part VI.1 tax transactions and amounts from its regulated statements in the future, and to adjust for any amounts currently included in the regulated financial statements; [para. 379]

- Keep the Annapolis Tidal Generation Facility in property, plant and equipment; [para. 387]

- Engage in a review process, with the Affordable Energy Coalition and the Consumer Advocate, to evaluate the impact of the changes approved in 2013 to bill payment, credit and collection matters, to examine if further changes are needed, and to establish a systematic evaluation methodology that can be applied to future changes. NS Power is to file a report by April 30, 2023; [para. 411]

- To explore options with NPCC about alternative treatment of interruptible loads and to file its analysis of cost implications in the next GRA; [para. 478]

- Explore, prior to the next GRA, alternative treatment of the -16 MW requirement in AGC and to demonstrate that it is not double charging transmission customers; [para. 482]

- 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 [para. 485]

- Provide a more fulsome explanation, no later than in its next GRA, to justify its position to exclude CT units from its costing of 30-minute supplemental reserve for the CBAS calculations. [para. 486]

9.0 COMPLIANCE FILING

[513] 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:

- The proposed changes to the miscellaneous charges in Regulation 7 and the proposed revisions to the various tariffs, including the Distribution Tariff, subject to the Board's findings elsewhere in this decision; [para. 490]

- Forecasted interest calculations to the end of 2024 for the existing deferrals approved for the recovery of interest at NS Power's WACC; [para. 114]

- Required changes to NS Power's FAM Plan of Administration based on the recovery of fuel and purchased power costs under the GRA Settlement Agreement and approved in this decision; [para. 159]

- Updated DCRR charges for 2023, recognizing that this GRA decision is being released after the October 1 DCRR filing date noted in the tariff; [para. 358] and

- Application of the 2-standard deviation methodology in the CBAS calculation. [para. 484]

[514] NS Power is directed to file a compliance filing no later than two weeks after the date of this decision. Intervenors will have two weeks 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.

[515] The Board has approved the average rate increases of 6.9% across all customer classes in each of 2023 and 2024, subject to the Board's findings in this decision. Schedule B attached to the GRA Settlement Agreement (i.e., Appendix B in this decision) sets out the rate increases per customer class, to be confirmed in the compliance filing. The Board approves the rates and charges for 2023 effective the date of this decision and the rates and charges for 2024 effective January 1, 2024.

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

DATED at Halifax, Nova Scotia, this 2nd day of February 2023.

Stephen T. McGrath

Roland A. Deveau

Steven M. Murphy

APPENDIX A

Intervenors **(Counsel or representative)**	**Witnesses/Pre-filed Evidence**
Nova Scotia Power Inc. Colin Clarke, K.C. Blake Williams	**Policy/Finance and DDA** Peter Gregg - President & CEO Chris Smith - EVP, Finance Lia Macdonald - VP Transmission/ Distribution/Delivery Craig Flemming - Director, Finance Brian Curry, Director - Regulatory Affairs Eric Ferguson - Senior Director Pricing Michael Willett -Director, Regulatory Finance John Reed CEO, Concentric Energy Advisors **Cost of Capital** Peter Gregg - President & CEO Chris Smith - EVP, Finance Craig Flemming - Director, Finance Michael Willett - Director, Regulatory Finance James Coyne - Senior VP, Concentric Energy Advisors **Riders/Rates/COS** Craig Flemming - Director, Finance Brian Curry - Director, Regulatory Affairs Eric Ferguson - Senior Director Pricing Michael Willett - Director, Regulatory Finance Voytek Grus - Manager, Costing and Rates Matthew Drover - Senior Director, Transmission & Distribution Daniel Dane - EVP, Concentric Energy Advisors Bickey Rimal - Assistant VP, Concentric Energy Advisors **Fuel/Purchased Power/Load** David Landrigan - VP Commercial Marie MacLean - Director, Fuels Brendan Chard - Director, Portfolio Optimization Michael Willett - Director, Regulatory Finance

Board Counsel S. Bruce Outhouse, K.C.	**<u>Bates White</u>** Vincent Musco Karen Morgan Nick Puga **<u>Grant Thornton</u>** Tom Brockway Barry Griffiths Angie Brown **<u>Synapse Energy Economics Inc.</u>** Melissa Whited Karl Pavlovic – PCMG Laurence Booth **<u>Plenus Actuaries and Consultants</u>** Paul Burnell
Consumer Advocate William J. Mahody, K.C. Emily Mason Christine Murray	**<u>Resource Insight Inc.</u>** Paul Chernick John Wilson J. Randall Woolridge
Small Business Advocate E.A. Nelson Blackburn, K.C. Melissa P. MacAdam	**<u>Daymark Energy Advisors</u>** John Athas Melissa Whitten
Industrial Group Nancy G. Rubin, K.C. Brianne E. Rudderham Dylan MacDonald	**<u>Drazen Consulting Group, Inc.</u>** Mark Drazen
Affordable Energy Coalition Peter Duke Brian Gifford	
Dalhousie University Nancy G. Rubin, K.C. Brianne E. Rudderham Dylan MacDonald	
Ecology Action Centre Jacob Thompson	

Eastlink Robert G. Grant, K.C.	**<u>AGBriggs Consulting Inc.</u>** Andrew Briggs Steve Irvine – Senior VP Energineer and Chief Technology Officer
Efficiency One James G. Gogan David Irvine	**<u>Elenchus</u>** John Todd
Freeman Lumber Noah Entwisle	
Heritage Gas Limited Michael Johnston Kristen Wilcott	
Mainland Telecom Inc. Burt McCaffrey	
Municipal Electric Utilities of Nova Scotia James MacDuff Melanie Gillis	Don Regan – Superintendent, Berwick Electric Commission Albert Dominie **<u>WKM Energy Consultants Inc.</u>** William Marshall
NCS Managed Services Emerich R. Winkler Jr.	
Nova Scotia Department of Natural Resources and Renewables Daniel Boyle Jeremy Smith David Miller Michelle Miller Peter Craig Christina Wells	**<u>Power Advisory LLC</u>** Christine Runge John Dalton
Nova Scotia Liberal Caucus Zach Churchill, M.L.A., Leader Kirby McVicar Callie Franson	Zach Churchill, M.L.A., Leader

Nova Scotia NDP Caucus Claudia Chender, M.L.A., Leader Susan Leblanc, M.L.A. Allison Smith Joanne Hussey	Claudia Chender, M.L.A., Leader
Port Hawkesbury Paper LP James MacDuff Melanie Gillis	
Rogers Communications Canada Inc. Leslie Milton	Dean Abbass – General Manager, Cable Operations as Seaside Communications
Xplore Inc. Carl MacQuarrie	Carl MacQuarrie – Regulatory Counsel at Xplore

APPENDIX B

Anticipated Revenue Increase Table

	2023				2024			
	Base Cost Rates	**FAM AA/BA Riders**	**DSM Rider**	**Total**	**Base Cost Rates**	**FAM AA/BA Riders**	**DSM Rider**	**Total**
Domestic Service Tariff								
Fuel	0.7%	0.0%	0.0%	0.7%	6.4%	0.0%	0.0%	6.4%
Non-Fuel	2.7%	0.0%	3.5%	6.2%	0.0%	0.0%	0.4%	0.4%
Total	**3.3%**	**0.0%**	**3.5%**	**6.9%**	**6.4%**	**0.0%**	**0.4%**	**6.8%**
Small General Tariff								
Fuel	0.7%	0.0%	0.0%	0.7%	8.3%	0.0%	0.0%	8.3%
Non-Fuel	2.9%	0.0%	4.8%	7.7%	0.0%	0.0%	0.1%	0.1%
Total	**3.6%**	**0.0%**	**4.8%**	**8.4%**	**8.3%**	**0.0%**	**0.1%**	**8.5%**
General Tariff								
Fuel	2.8%	0.0%	0.0%	2.8%	6.8%	0.0%	0.0%	6.8%
Non-Fuel	0.3%	0.0%	4.0%	4.3%	0.0%	0.0%	0.2%	0.2%
Total	**3.1%**	**0.0%**	**4.0%**	**7.1%**	**6.8%**	**0.0%**	**0.2%**	**7.0%**
Large General Tariff								
Fuel	1.7%	0.0%	0.0%	1.7%	8.3%	0.0%	0.0%	8.3%
Non-Fuel	1.8%	0.0%	4.8%	6.6%	0.0%	0.0%	0.0%	0.0%
Total	**3.5%**	**0.0%**	**4.8%**	**8.3%**	**8.3%**	**0.0%**	**0.0%**	**8.3%**
Small Industrial Tariff								
Fuel	-0.7%	0.0%	0.0%	-0.7%	8.4%	0.0%	0.0%	8.4%
Non-Fuel	4.2%	0.0%	4.7%	8.8%	0.0%	0.0%	0.0%	0.0%
Total	**3.5%**	**0.0%**	**4.7%**	**8.1%**	**8.4%**	**0.0%**	**0.0%**	**8.5%**
Medium Industrial Tariff								
Fuel	0.7%	0.0%	0.0%	0.7%	8.0%	0.0%	0.0%	8.0%
Non-Fuel	5.0%	0.0%	2.2%	7.2%	0.0%	0.0%	0.2%	0.2%
Total	**5.7%**	**0.0%**	**2.2%**	**7.9%**	**8.0%**	**0.0%**	**0.2%**	**8.2%**
Large Industrial Tariff								
Fuel	5.2%	0.0%	0.0%	5.2%	4.8%	0.0%	0.0%	4.8%
Non-Fuel	-3.3%	0.0%	3.0%	-0.3%	0.0%	0.0%	0.0%	0.0%
Total	**1.9%**	**0.0%**	**3.0%**	**4.9%**	**4.8%**	**0.0%**	**0.0%**	**4.8%**

Municipal Tariff								
Fuel	-3.4%	0.0%	0.0%	-3.4%	5.9%	0.0%	0.0%	5.9%
Non-Fuel	3.9%	0.0%	4.8%	8.8%	0.0%	0.0%	0.2%	0.2%
Total	**0.5%**	**0.0%**	**4.8%**	**5.4%**	**5.9%**	**0.0%**	**0.2%**	**6.1%**
Unmetered								
Fuel	3.0%	0.0%	0.0%	3.0%	0.1%	0.0%	0.0%	0.1%
Non-Fuel	-3.5%	0.0%	0.7%	-2.8%	0.0%	0.0%	0.0%	0.0%
Total	**-0.5%**	**0.0%**	**0.7%**	**0.2%**	**0.1%**	**0.0%**	**0.0%**	**0.2%**
Total FAM Classes								
Fuel	1.5%	0.0%	0.0%	1.5%	6.6%	0.0%	0.0%	6.6%
Non-Fuel	1.8%	0.0%	3.6%	5.4%	0.0%	0.0%	0.3%	0.3%
Total	**3.3%**	**0.0%**	**3.6%**	**6.9%**	**6.6%**	**0.0%**	**0.3%**	**6.9%**

NOTE: The increases identified above are subject to change as a result of the proceeding's compliance filing.