Nova Scotia Energy Board

IN THE MATTER OF *The Public Utilities Act,* R.S.N.S. 1989, c.380, as amended

- and -

IN THE MATTER OF an Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges, and Regulations

2026-2027
General Rate Application
M12451

Partially Confidential
(Attachments Only)

September 18, 2025

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1 INTRODUCTION

1.1 Support for 2026-2027 GRA

Further to the letter filed with the Nova Scotia Energy Board (NSEB or Board) on September 2, 2025, Nova Scotia Power Incorporated (NS Power or Company) is filing this General Rate Application for 2026-2027 (GRA). As discussed in the letter, this GRA is the result of an extensive collaborative process involving NS Power and customer representatives, who, as a result of that process, are supportive of the outcomes being requested in this GRA. As noted in the letter, the following customer representatives have provided their support: the Consumer Advocate (CA), Small Business Advocate (SBA), counsel for the Industrial Group, representing CKF Inc., Crown Fibre Tube Inc., Irving Shipbuilding Inc., K + S Windsor Salt Ltd., Maritime Paper Products Ltd., Michelin North America (Canada) Inc., Compass Minerals Canada Corp., Farnell Packaging Ltd., P & H Milling Group, and PSA Halifax (IG), counsel for the Berwick Electric Commission, Riverport Electric Light Commission, the Town of Mahone Bay, and the Town of Antigonish (the Municipal Electric Utilities, or MEUs), and counsel for Port Hawkesbury Paper (PHP) (Customer Representatives and, collectively with NS Power, the Parties).

This GRA was built off the substantive and thorough Cost-of-Service Study (COSS), which was directed by the NSEB and then initiated by NS Power on December 13, 2023 (M11475). This COSS was carried out with customer representatives, Board counsel and staff, and participants' expert consultants throughout 2024 and early 2025. This GRA was then subsequently developed over several months and its development included multiple technical conferences and meetings between the NS Power and Customer Representatives to discuss and understand all Parties' positions on the various elements of the GRA. Hundreds of detailed questions and requests for additional information from Customer Representatives were responded to by NS Power and, the Parties participated in multiple meetings where the GRA was negotiated, with the result being a consensus on the outcomes. Throughout the entirety of this process, Customer Representatives were aided by their expert consultants.

NS Power recognizes that the cybersecurity attack has impacted customers, and we are committed to limiting that impact as much as we can. To that end, this GRA does not include costs related to the cybersecurity attack. To be clear, the 2026-2027 revenue requirement forecast that forms the basis of this GRA was developed prior to the attack and it has not been adjusted in any way to account for costs arising from the attack.

As previously described, the process that has been undertaken to develop this GRA has been extensive. The resulting support of the customer representatives for the outcomes of the GRA is comprehensive, in that the parties do not require and are not seeking a process that provides an opportunity for them to make information requests or submit evidence, provided the GRA is filed in accordance with the terms of the negotiated outcome. Indeed, this collaborative outcome includes reduced costs to account for the anticipated GRA-related regulatory efficiencies that have been created by the parties' collaborative efforts and work.

While NS Power understands and appreciates the views expressed by the Board in its September 5, 2025 letter, it is the Company's hope and expectation that the broad support from experienced customer representatives, aided by expert consultants, gives the Board confidence that this GRA is in the public interest and results in regulatory efficiencies.

1.2 Overview of 2026-2027 GRA

NS Power submits this GRA to the Board to request approval of revenue requirements for the utility and request adjustments to electricity rates for 2026 and 2027, effective January 1, 2026 and 2027.

The NS Power team is focused on delivering reliable, affordable and safe electricity to Nova Scotians. We are committed to doing this safely every single day and in a way that manages operating costs and capital investments in the best interests of customers.

We know that these are uncertain times with global politics and events driving economic impacts here at home. We understand that costs for everything from gas to groceries to housing seem to be going up regularly and we also understand that in today's evolving world, electricity service and the reliability of that service have never been more important to our customers. This application is required now to ensure we can continue to strengthen system reliability, build resilience against increasingly volatile and extreme weather, and to support Nova Scotia's economic development and the government's decarbonization goals. It is also required to ensure

NS Power's financial health, allowing the Company to carry out this important work on behalf of Nova Scotians. We have worked hard with customer representatives to balance both the reliability and affordability priorities to put forward a broadly supported proposal to fund the electricity services customers deserve and need in a cost-effective manner.

With this application, NS Power is seeking an average annual rate increase of 1.8 percent in 2026 and 2.4 in 2027. The specific increase for each group of electricity customers will ultimately vary based on the method approved by the Board to apportion costs between customer classes (the Cost of Service). NS Power's proposal results in 3.8 percent and 4.1 percent rate increases for Domestic Class (residential) customers in 2026 and 2027, respectively. The proposal also results in rate decreases in both years for Large and Medium Industrial customers, as well as the Large General class of customers, which includes hospitals and universities.

The proposed rate impacts of this GRA can be compared to the recent annual average rate increases of 7 percent to nearly 13 percent, which are being experienced by our Atlantic Canadian neighbors. NS Power has worked relentlessly to keep costs down in all aspects of its operations, as well as working with the provincial and federal governments to find ways to reduce cost pressures on customers. The benchmarking study provided in standardized filing **OP-03 Attachment 1** of the GRA illustrates that NS Power's costs are below or in line with electric utility norms, and that NS Power performs favourably compared to its peers and generally in the top quartile.

1.3 Customer Growth and Support

Since 2022, NS Power's customer count has increased by 21,000 to approximately 559,000. That is unprecedented and exciting growth in Nova Scotia in a very short time. This growth has been driving a 30 percent surge in customer work requests. In 2024 alone, we processed 27,000 wiring permits and completed 44,000 electrical inspections, 4,400 renovations, and 8,400 new customer connection requests. To meet these demands, we have hired more Nova Scotians into our customer-focused and front-line teams, adding dozens of Wiring Inspectors, Permit Centre employees and Powerline Technicians, as well as Planners and Planning Coordinators who scope and plan customer work. We have also been actively supporting over 7,200 new solar net metering customers, bringing our total number of net metering customers to over 11,000.

In addition to the foregoing efforts to support customers, we have also enhanced our engagement with Low Income Advocates and evolved our outreach strategies to ensure our customers know how to find the help they need. This has led to a significant reduction in residential disconnections (3,158 in 2023 vs. 1,782 in 2024) as we assist more customers in finding solutions, including offering 12-month and 24-month payment plans for outstanding balances.

With the support of the CA and the Affordable Energy Coalition, NS Power also sought and received approval from the Board for a pilot program to waive interest charges for customers in arrears who receive financial support from charitable organizations.

1.4 Reliability and System Strength

We know that our customers expect and deserve reliable electricity. That’s why we are focused on strengthening the power grid and ensuring we meet the clear expectations of our customers, regulator and Government.

To do this, NS Power is advancing innovative large-scale capital projects that will ensure the stability of the electricity grid as Nova Scotia continues its energy transition, replacing fossil fuels with renewable energy sources at a pace that best serves Nova Scotians. This includes Atlantic Canada’s largest grid-scale battery facilities in Bridgewater, White Rock and Waverley, as well as the NS-NB Reliability Intertie. These projects are designed not only to make progress towards the government’s clean energy goals, but also to enhance reliability and ensure a strong and robust grid into the future. In addition, our team members are continuously inspecting, testing, and improving our infrastructure through proactive, data-driven plans and innovative technology to better stand up to changing weather, including investments in more robust equipment, maintenance, and tree trimming. We are also continuing to engage our customers in important discussions around reliability, to ensure we understand their expectations, with over 65 community meetings held throughout Nova Scotia to discuss these initiatives.

In 2024, $200 million was invested in reliability and included replacing 3,000 poles and clearing trees from 1,500 kilometers of power lines. In that same year, power was on 99.9 percent of the time, surpassing the Canadian average of 99.73 percent.

We have a plan to continue to increase reliability investment to an annual average of $250b million through 2025-2029, a 25 percent increase over previous years, with $485 million planned to be spent in 2026 and 2027. The distribution, transmission, and substation upgrade projects and work that this spending will provide for, include:

- New high voltage protective device to reduce outages between Middlefield and Maitland Bridge.
- New Bridgewater substation to support load growth.
- Subsea cable replacements for Brier Island and upgrading targeted power lines in the area.
- New Stellarton substation and transformer replacements to support load growth and upgrade infrastructure.
- Smart Grid upgrades in Pictou East for improved communications and switching.
- Reduce planned outages in Amherst area through upgrading the switching capacity of the power system.
- Smart Grid enhancements to in Cape Breton to allow for quicker response to power outages by pinpointing the location of the cause for 5,500 customers, including Eskasoni First Nations.
- Multiple voltage conversions in Sampsons Cove and Arichat areas to upgrade assets and support load growth.
- Transformer replacements in Glace Bay and Aberdeen to upgrade existing infrastructure.
- New Bayers Lake substation to support load growth.

- Smart Grid enhancements to allow for quicker response to power outages by pinpointing the location of the cause for Lakeside, Hammonds Plains, and Kearney Lake communities.
- Adding a second circuit for 4.5 km along Peggy's Cove Road to address customer load issues.

1.5 Working with Government on Solutions for Nova Scotia

NS Power has been working collaboratively with the Provincial and Federal Governments to find ways to reduce costs and alleviate rate pressure on customers. These efforts to create solutions include the arrangement to reduce the costs to customers of Nova Scotia's unrecovered fuel balance. The $117 million receivable purchased by Invest Nova Scotia and the $500 million Federal Government Loan Guarantee have reduced rate pressure for customers while also providing Nova Scotians with approximately $60 million in overall savings.

NS Power also worked with the Provincial Government to adjust sulphur emission regulations. This change will allow NS Power and our customers to save approximately $160 million over the 2026-2027 period while keeping overall provincial sulphur emissions below the Nova Scotia limit. This approach also better aligns with the energy transition path that we are on in Nova Scotia, as we introduce more renewable energy in the province. This work with the Provincial Government has also resulted in the development of a securitization approach, related to key thermal assets, under section 35G of the *Public Utilities Act*. When put into effect, this approach could save customers as much as $90 million over 2026-2027 by removing these assets from NS Power's rate base and financing them through lower-cost debt.

These efforts reflect the commitment to Nova Scotians that we share with the provincial and federal governments.

1.6 Roadmap of the Application

This application is organized into several key components, each critical to determining the proposed rate adjustments:

1. **Status of Prior GRA-Related Directives:** An update on the various directives from the NSEB which are required to be complete before or as part of this filing

2. **Load Forecast**: An analysis of anticipated electricity demand, considering economic trends, population growth, and energy efficiency initiatives.

3. **Fuel and Purchased Power Overview**: A review of projected fuel costs and power purchases.

4. **Fuel Adjustment Mechanism (FAM)**: An explanation of the mechanism that adjusts rates to reflect actual fuel costs, ensuring alignment with market fluctuations.

5. **Operating Costs**: A detailed account of the Company's expenses, including labour, maintenance, and administrative operations, required to deliver reliable service.

6. **Depreciation and Regulatory Deferrals**: A detailed overview of the updated depreciation study as per the Board's directive in the last GRA,[1] information on asset depreciation schedules, and any deferred costs subject to regulatory approval. Further, as directed by the Board in its 2024 ACE decision, NS Power has included an updated capital cost estimate for the Mersey decommissioning option in **Appendix 8B**, complete with all assumptions used. Costs for decommissioning Tusket and Wreck Cove are also included in Appendix 8B, although NS Power is not proposing to decommission any of those three hydro sites.

7. **Rate Base**: A summary of NS Power's invested capital, including infrastructure and equipment, that forms the basis for earning an authorized return.

8. **Capital Structure and Financing**: Details of the Company's financial framework, including the debt-to-equity ratio and the cost of capital.

9. **Revenue Requirement**: The total revenue needed to cover fuel and non-fuel expenses, ensuring the financial stability required to improve reliability and meet customers' expectations.

10. **Cost of Service**: Details of the Company's cost of service methodology including a line loss study as directed by the Board in its Decision on the 2023-2024 GRA.

11. **Rate Design**: A presentation of proposed rate structures designed to equitably distribute costs among customer classes, including AMI opt-out.

12. **Proposed Rates**: Tables showing the rate requests for both years of the test period by rate class.

13. **Regulation Changes**: Updates to NS Power's Regulations related to GRA items (such as Meter Reading).

This is the application that has been arrived at collaboratively with customer representatives in an attempt to balance affordability with customers' expectations on reliability, the need to advance the clean energy transition goals outlined by government and to maintain a strong utility that can meet the needs of Nova Scotians into the future.

2 NS POWER'S REQUEST

2.1 Electricity Rate Impact

In this GRA, Nova Scotia Power is forecasting and seeking approval for a total revenue requirement of $2.0 billion in 2026 and $2.0 billion in 2027. As previously noted, the rates that are being applied for in this Application will therefore result in an overall average increase for customers of approximately 1.8 percent in 2026 and 2.4 percent in 2027, but with rate decreases for certain customer classes. A breakdown of the average increases per customer class is set out below in **Figure 2-1**.

Figure 2-1 – 2026-2027 Proposed Rate Impacts (Percentage Change)

Customer Class	2026	2027
Domestic Service		
Fuel	1.2	(0.4)
Non-Fuel	2.6	4.4
Total	3.8	4.1
Small General		
Fuel	2.7	(0.8)
Non-Fuel	1.0	4.8
Total	3.7	4.0
General		
Fuel	3.5	(3.2)
Non-Fuel	(3.6)	3.7
Total	(0.1)	0.5
Large General		
Fuel	3.8	(5.7)
Non-Fuel	(8.2)	2.5
Total	(4.4)	(3.2)
Small Industrial		
Fuel	4.7	(3.3)
Non-Fuel	(5.2)	3.5
Total	(0.4)	0.3
Medium Industrial		
Fuel	3.8	(6.7)
Non-Fuel	(10.3)	1.9
Total	(6.4)	(4.8)

Customer Class	2026	2027
Large Industrial Firm Transmission Service		
Fuel	4.1	(6.6)
Non-Fuel	(10.2)	2.4
Total	(6.2)	(4.3)
Large Industrial Firm Distribution Service		
Fuel	3.9	(6.3)
Non-Fuel	(9.3)	2.6
Total	(5.4)	(3.7)
Large Industrial Interruptible Transmission Service		
Fuel	4.9	(8.0)
Non-Fuel	(11.9)	2.6
Total	(7.0)	(5.4)
Large Industrial Interruptible Distribution Service		
Fuel	4.5	(7.5)
Non-Fuel	(11.8)	3.3
Total	(7.3)	(4.2)
Large Industrial Total		
Fuel	4.6	(7.6)
Non-Fuel	(11.5)	2.8
Total	(6.9)	(4.7)
Municipal Class		
Fuel	9.6	(0.4)
Non-Fuel	(7.9)	3.4
Total	1.7	3.0
Unmetered Class		
Fuel	(0.7)	2.8
Non-Fuel	8.6	4.6
Total	7.9	7.3
Total FAM Classes		
Fuel	2.3	(1.7)
Non-Fuel	(0.5)	4.1
Total	1.8	2.4

The proposed rates for each of NS Power's tariffs are set out in **Figure 2-2** and **Figure 2-3** for 2026 and 2027, respectively.

Figure 2-2 – 2026 Proposed Rate Summary

Proposed Rate Changes	Units	Current 2025	Proposed for 2026	Percentage Change
Domestic Service Tariff				
Customer Charge	$/mo.	19.17	20.24	5.6
Energy Charge	¢/kWh	17.928	18.610	3.8
DSM Rider	¢/kWh	0.633	0.633	0.0
Small General Tariff				
Customer Charge	$/mo.	21.28	22.16	4.1
Energy Charge (Block 1, first 200 kWh)	¢/kWh	18.474	19.209	4.0
Energy Charge (Block 2)	¢/kWh	16.748	17.380	3.8
DSM Rider	¢/kWh	0.753	0.753	0.0
General Tariff				
Demand Charge	$/kW	10.554	9.838	-6.8
Energy Charge (Block 1, first 200 kWh)	¢/kWh	14.977	15.053	0.5
Energy Charge (Block 2)	¢/kWh	11.680	11.980	2.6
DSM Rider	¢/kWh	0.646	0.646	0.0
Large General Tariff				
Demand Charge	$/kVA	13.845	11.201	-19.1
Energy Charge	¢/kWh	11.507	11.397	-1.0
DSM Rider		0.790	0.790	0.0
Small Industrial Tariff				
Demand Charge	$/kVA	8.332	7.506	-9.9
Energy Charge (Block 1, first 200 kWh)	¢/kWh	13.873	14.010	1.0
Energy Charge (Block 2)	¢/kWh	11.299	11.692	3.5
DSM Rider	¢/kWh	0.753	0.753	0.0
Medium Industrial Tariff				
Demand Charge	$/kW	13.796	10.728	-22.2
Energy Charge	¢/kWh	11.044	10.952	-0.8
DSM Rider	¢/kWh	0.314	0.314	0.0

Proposed Rate Changes	Units	Current 2025	Proposed for 2026	Percentage Change
Large Industrial Tariff				
Demand Charge	$/kVA	12.601	9.280	-26.4
Interruptible Credit	$/kVA	-7.486	-7.638	2.0
Distribution Cost Adder	$/kVA	1.632	2.332	42.9
Energy Charge (Firm-Transmission)	¢/kWh	10.799	10.614	-1.4
Energy Charge (Firm - Distribution)	¢/kWh	10.836	10.614	-1.7
Energy Charge (Interruptible - Transmission)	¢/kWh	10.776	10.630	-1.0
Energy Charge (Interruptible - Distribution)	¢/kWh	10.813	10.630	-1.4
DSM Rider	¢/kWh	0.431	0.431	0.0
Municipal Tariff				
Demand Charge	$/kVA	13.428	11.330	-15.6
Energy Charge	¢/kWh	10.658	11.741	10.2
DSM Rider	¢/kWh	0.627	0.627	0.0

Figure 2-3 – 2027 Proposed Rate Summary

Proposed Rate Changes	Units	Proposed 2026	Proposed for 2027	Percentage Change
Domestic Service Tariff				
Customer Charge	$/mo.	20.24	21.38	5.6
Energy Charge	¢/kWh	18.610	19.372	4.1
DSM Rider	¢/kWh	0.633	0.633	0.0
Small General Tariff				
Customer Charge	$/mo.	22.16	23.07	4.1
Energy Charge (Block 1, first 200 kWh)	¢/kWh	19.209	20.107	4.7
Energy Charge (Block 2)	¢/kWh	17.380	18.081	4.0
DSM Rider	¢/kWh	0.753	0.753	0.0
General Tariff				
Demand Charge	$/kW	9.838	10.709	8.9

Proposed Rate Changes	Units	Proposed 2026	Proposed for 2027	Percentage Change
Energy Charge (Block 1, first 200 kWh)	¢/kWh	15.053	15.029	-0.2
Energy Charge (Block 2)	¢/kWh	11.980	11.683	-2.5
DSM Rider	¢/kWh	0.646	0.646	0.0
Large General Tariff				
Demand Charge	$/kVA	11.201	11.201	0.0
Energy Charge	¢/kWh	11.397	10.760	-5.6
DSM Rider		0.790	0.790	0.0
Small Industrial Tariff				
Demand Charge	$/kVA	7.506	8.143	8.5
Energy Charge (Block 1, first 200 kWh)	¢/kWh	14.010	13.894	-0.8
Energy Charge (Block 2)	¢/kWh	11.692	11.379	-2.7
DSM Rider	¢/kWh	0.753	0.753	0.0
Medium Industrial Tariff				
Demand Charge	$/kW	10.728	11.277	5.1
Energy Charge	¢/kWh	10.952	10.095	-7.8
DSM Rider	¢/kWh	0.314	0.314	0.0
Large Industrial Tariff				
Demand Charge	$/kVA	9.280	10.000	7.8
Interruptible Credit	$/kVA	-7.638	-7.667	0.4
Distribution Cost Adder	$/kVA	2.332	2.527	8.3
Energy Charge (Firm-Transmission)	¢/kWh	10.614	9.925	-6.5
Energy Charge (Firm - Distribution)	¢/kWh	10.614	9.925	-6.5
Energy Charge (Interruptible - Transmission)	¢/kWh	10.630	9.882	-7.0
Energy Charge (Interruptible - Distribution)	¢/kWh	10.630	9.882	-7.0
DSM Rider	¢/kWh	0.431	0.431	0.0
Municipal Tariff				
Demand Charge	$/kVA	11.330	12.270	8.3
Energy Charge	¢/kWh	11.741	11.892	1.3
DSM Rider	¢/kWh	0.627	0.627	0.0

2.2 FAM Treatment

With respect to the fuel-related GRA amounts and Actual Adjustment / Balance Adjustment (AA/BA) riders and rates, the FAM will continue to operate.

Nova Scotia Power is seeking approval of new Base Cost of Fuel (BCF) amounts for each of 2026 and 2027 based on the forecast set out in **FOR-07**. It is anticipated that the FAM AA/BA riders will operate in the normal course.

2.3 Nova Scotia Power's Request

In this GRA, Nova Scotia Power is seeking an order from the Board approving the following:

1. The 2026 and 2027 revenue requirements as described in **Section 11** to enable NS Power to recover the prudent and reasonable costs of providing service to customers and to meet its financial obligations.

2. As described in **Section 5**, the BCF amounts attributable to FAM customers be set at $927.3 million for 2026 and $850.9 million for 2027, which represent the smoothed amounts.

3. The amendments to the FAM Plan of Administration as described in **Section 6** and **Appendix 6A** and set out in **Appendix 6B**.

4. As set out in **Section 5**, the change to the language in the introduction to Appendix Q (the Hedging Plan) of the Fuel Manual so that it is generic and not tied to specific years or rate periods. This change is administrative and does not affect the substantive content of NS Power's Hedging Plan or specific hedging targets.

5. As set out in **Section 8**, inclusion of GRA-related costs in the deferral and regulatory asset previously approved by the Board in its 2023-2024 GRA Decision for COSS, Line Loss Study, and Climate Change Adaptation Plan costs.

6. As described in **Section 9.2**, if securitization of the unrecovered net book value of generation assets within the scope of the DDA is delayed such that it cannot be completed

in whole or in part by January 1, 2026, NS Power is requesting that depreciation expense and financing costs of these assets be deferred at WACC on an interim basis. S

7. As set out in **Section 11.2**, approval of the EIFEL Deferral.
8. As set out in **Section 12.4**, approval of the PHP Deferral.
9. As set out in **Appendix 12A**, the updated Cost-of-Service Study**.**
10. All rates, charges and regulations requested in this Application, which, in addition to the rates set out in **Section 14 Figure 14-1, Figure 14-2, and Figure 14-3** and **PR-01 and PR-03.**
11. Continuation of the Storm Cost Recovery Rider pilot in 2026 and 2027, but on a symmetrical basis as described in **Section 13.6**.
12. Nova Scotia Power's Capital Structure and Cost of Capital as described in **Section 10**.
13. Such other relief as may be required to bring effect to that which is requested herein.

The relief requested by NS Power is subject to such further information as may be provided by the Company to the Board throughout the regulatory process, including its Compliance Filing.

3 STATUS OF PRIOR GRA-RELATED DIRECTIVES

When the NSEB rendered its decision following the 2023-2024 GRA, it issued 13 directives for NS Power arising from the issues at the hearing. The Board has also issued other directives which require compliance on or before filing the current GRA. The Board directives and status updates (including a summary table) are provided in **Appendix 3A.**

4 LOAD FORECAST

4.1 Overview

Planning for Nova Scotia's electricity system requires an estimation of how much power customers will consume over the course of a year, and load affects both planning and operational costs:

- Total electricity usage determines the variable operating costs (including fuel); and
- Peaks in demand determine the amount and long-term fixed costs of generating, transmission and distribution capacity needed for the system

NS Power calculates its load forecast each year, and the forecast plays an essential part in forecasting costs and allocating them among different customer classes, in accordance with cost-of-service principles and models.

The Load Forecast assesses total electricity consumption and peak demand. NS Power's Load Forecast methodology and components have evolved over the years. The 2026-2027 Load Forecast, information about how NS Power develops the Load Forecast and the inputs and assumptions used are provided in **SR-02**.

NS Power's forecast for net energy consumption in the province over the two-year test period was produced in September of 2024 using an updated version of the 2024 Load Forecast filed in April 2024 as noted in **Figure 4-1** below.

Figure 4-1 – Load Forecast 2026-2027

Year	Anticipated Load (GWh)
2026	11,392
2027	11,311

The main differences between the 2024 Load Forecast and the GRA forecast are as follows:

- Updated assumption for Renewable to Retail (RTR), with a total of 300 GWh moving to the RTR market in 2026 and a total of 421 GWh in 2027. For context, the 2024 Load Forecast assumed 61 GWh moving to RTR in 2025 and a total of 246 GWh in 2026.
- Updated economic forecast (May 2024)
- Updated actual sales (up to May 2024)

Electricity rates are a function of the cost to provide service (the revenue requirement) and the total amount of electricity used in Nova Scotia homes, businesses, and workplaces (the system load). If the revenue requirement remains constant from year to year, but the electricity sales decrease, customer rates would need to increase.

The load forecast breaks down the expected provincial load into three main categories (residential, commercial, and industrial). It divides each of these into the various customer sales classes. The 2024 Load Forecast Report, provided in **SR-02 Attachment 2**, provides this breakdown in greater detail.

The key points of the GRA load forecast for 2026 and 2027 are as follows:

- Sales – compared to the 2024 Load Forecast, sales increased 86 GWh in 2026 and decreased 36 GWh in 2027. The changes are due mainly to forecast increases in residential and commercial sales, offset by forecast increases in RTR migration in 2027.
- Growth continues to be driven mainly by new residential customers and increased electrification of space heating. Like the 2024 Load Forecast, the current forecast still shows a drop in sales in 2026 and again in 2027 related to migration to the RTR market. The year over year change is forecast to be -1.4 percent in 2026 and -0.8 percent in 2027.

Demand is also expected to be driven mainly by new residential customers and electrification of space heating loads. While migration to RTR reduces sales, it has no impact on forecast peak demand, which is expected to increase by 0.4 percent in 2026 and 1.2 percent in 2027.

The 2024 Load Forecast and subsequently the GRA 2026 and 2027 Load Forecast assumed that the four OATT MEUs were not taking bundled service from NS Power, as applications for BUTU service for Ellershouse and out-of-province third-party supply were provided to NS Power by the four OATT MEUs. As part of the consultation process with stakeholders, the four OATT MEUs confirmed that these customers would be taking a portion of their load through the Municipal Tariff in 2026 and 2027. Therefore, for rate-making purposes NS Power has adjusted the load for the Municipal class to include this additional load and a decrease in the BUTU.

5 FUEL AND PURCHASED POWER

5.1 Overview

NS Power is seeking approval of new Base Cost of Fuel (BCF) amounts for FAM customers in 2026 and 2027 as set out in **FOR-07 Attachment 1**.

Fuel and purchased power are direct pass-through costs, with customers paying the actual prudently incurred costs. In addition to the fuel and purchased power costs being audited every two years by an independent auditor appointed by the NSEB, NS Power provides monthly, quarterly, and annual updates on the fuel costs throughout each year. Actual costs for FAM customers will be tracked during the 2026-2027 GRA Period and the FAM AA/BA riders will be used to collect or refund, under or over recoveries of fuel and purchased power costs. To facilitate having more uniform increases across the two test years, NS Power has adjusted the BCF fuel rates to produce an overall smoothed increase in the total rates. This results in NS Power setting rates to have an over-collection of fuel costs in 2026 and then having a corresponding under-collection of fuel costs in 2027.

The forecast fuel and purchased power costs for the two-year test period amount to $1.8 billion, with $919 million in 2026 and $918 million in 2027.[1] In 2025 the Supplemental Federal Loan Guarantee (FLG) costs were collected through the AA Rider as the BCF was not reset in 2025. For 2026 and beyond, the Supplemental FLG costs will no longer be collected through the FAM riders and will be included in the BCF. The increases in **Figure 5-1** and **Figure 5-2** below represent the net change which includes the removal of the FAM AA Rider for the Supplemental FLG in 2026 offset by the increase in the BCF for 2026, which includes the Supplemental FLG costs.

Figure 5-1 – 2026-2027 Fuel Rate Percentage Changes without Smoothing

Customer Class	2026	2027
Residential	0.7	0.7
Small General	2.0	0.5
General	2.2	(0.4)
Large General	1.9	(1.6)

[1] Total Fuel and Purchased Power including 4 OATT MEUs taking partial bundled Municipal Tariff results in $924.3 million in 2026 and $925.0 million in 2027.

Customer Class	2026	2027
Industrial		
Small	3.5	(0.7)
Medium	1.9	(2.1)
Large Industrial		
Firm Transmission Service	2.1	(2.0)
Firm Distribution Service	2.0	(1.9)
Interruptible Transmission Service	2.3	(2.3)
Interruptible Distribution Service	2.2	(2.1)
Large Industrial Total	2.2	(2.2)
Municipal	9.1	0.6
Unmetered	1.0	(0.7)
Total	1.4	0.1

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

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

Based on the two-year BCF forecast, NS Power is applying for an average 2.3 percent annual increase in FAM customer rates from 2026 and a reduction of 1.7 percent in 2027.

The price of commodities continues to be volatile, and NS Power will continue to mitigate the price fluctuations through hedging to provide value for customers. Hedging limits the volatility in fuel rates which would otherwise result from swings in commodity prices. NS Power's detailed hedging program is provided in Standardized Filing **OE-01J Attachment 1** and **Appendix 5B**.

Detailed information about generation by fuel type, the fuels forecast, the impact of the Maritime Link energy and updated hedging is set out in **Appendix 5A**.

NS Power's currently approved version of the Confidential Fuel Manual, which sets out the requirements for fuel and purchased power procurement, is included in Standardized Filing **OE-01F** and the Hedging Plan with a minor language change is included in **Appendix 5B.** The language of the preamble to Appendix Q (which is an overview of the Hedging Plan) in the Fuel Manual has been updated to refer to the plan in a generic way, rather than referencing specific years and filings which need to be updated. This is an administrative change only and does not affect the substantive content of the Fuel Manual or the Hedging Plan. NS Power seeks the Board's approval of this change in **Section 17** below.

5.2 Environmental Compliance

NS Power continues to make significant progress in reducing its emissions of mercury, sulphur dioxide, nitrogen oxide and greenhouse gases. NS Power is subject to various provincial standards governing the acceptable level of emissions.

The Air Quality Regulations, N.S. Reg. 8/2020 prescribe the limits on emissions in the province and are set out in **Figure 5-3** below.

Figure 5-3 – Emissions Limits 2025-2030

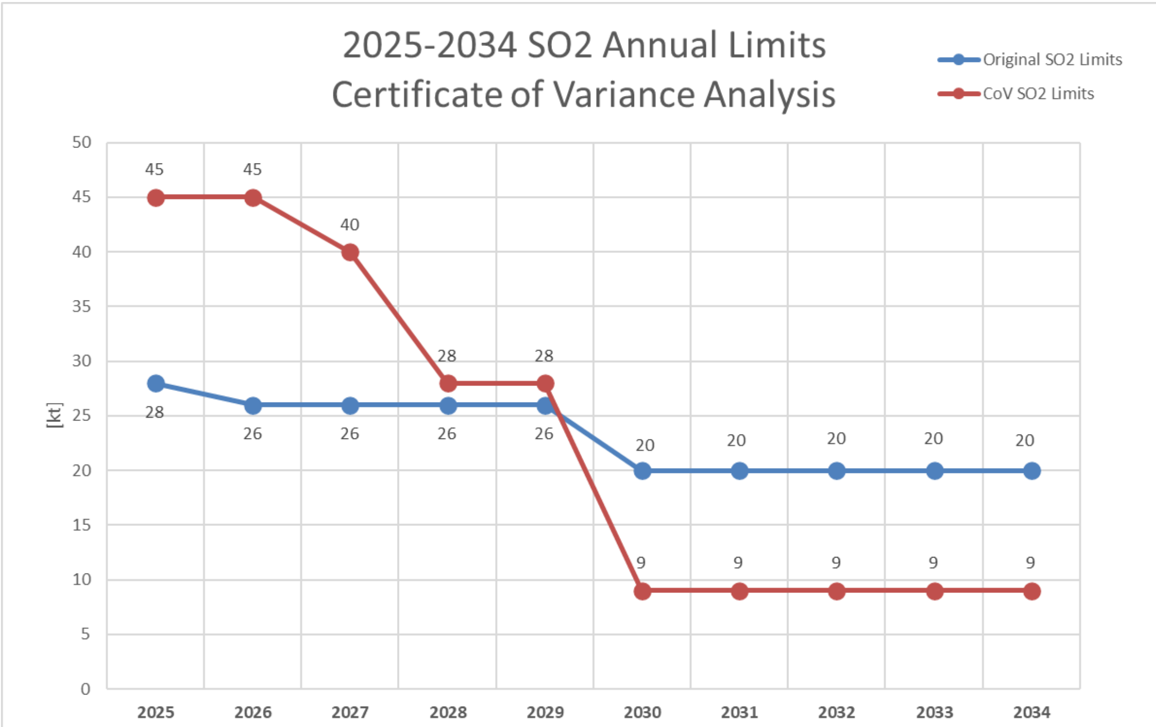
Emission	Year	Emissions Limit
Sulphur Dioxide (SO_2)	2025	45,000 t (annual) 13,720 t (individual unit)
	2026	45,000 t (annual) 13,720 t (individual unit)
	2027	40,000 t (annual) 13,720 t (individual unit)
	2028-2029	28,000 t (annual) 13,720 t (individual unit)

Emission	**Year**	**Emissions Limit**
	2026-2029 2030	141,000 t (NS Power fleet) 9,000 t (annual) 9,000 t (individual unit)
Nitrogen Oxide (NOx)	2025 2026-2029	11,500 t (NS Power fleet) 44,000 t (NS Power fleet)
Mercury (Hg)	2025 onward	35 kg aggregate (NS Power fleet)

Compliance with emissions limits can be a significant factor in the overall cost of fuel and purchased power. NS Power has worked with the Provincial Government to find a way to reduce cost pressures for customers while still ultimately achieving the required emissions compliance. With respect to sulphur dioxide, the Provincial Government has provided NS Power a certificate of variance (included as **Appendix 5C)** under section 61 of the ***Environment Act*** affecting allowable sulphur dioxide emissions (SO_2) which gives NS Power flexibility to better align SO_2 emission limits with the introduction of renewable energy to Nova Scotia. The result is a net-neutral impact to the environment, but a significant benefit to customers. This variance decreases NS Power's revenue requirement by approximately $160 million over the two-year test period.

The changes in SO_2 emissions limits under the certificate of variance are set out in **Figure 5-4** below.

Figure 5-4 – Sulphur Dioxide Annual Limits 2025-2034 with Variance



6 FUEL ADJUSTMENT MECHANISM

Fuel costs comprise a portion of the energy charge on customers' bills. NS Power charges actual fuel costs to customers and does so by using the Fuel Adjustment Mechanism (FAM). The FAM is governed by the Plan of Administration (the currently approved version of which is found in **OE-01R**). Under the FAM, actual fuel costs are charged to customers each year, based on anticipated load. There is an actual adjustment (AA) true-up mechanism to account for any differences between the amounts charged in the year and the actual fuel and purchased power costs incurred. There is also a balance adjustment (BA) true-up mechanism which accounts for sales volume variances in recovery/refund of the AA balance and any other amounts owing to or owed by customers, including any prior deferred amounts or charges as directed by the NSEB.

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

7 OPERATING COSTS

7.1 Overview

NS Power's operating, maintenance and general (OM&G) costs fall broadly into three areas:

- operating and maintaining the generation, transmission, and distribution facilities;
- delivering service to customers; and
- providing corporate support to those functions.

NS Power forecasts its total OM&G expense at $351.8 million in 2026 and $357.9 million in 2027. This is approximately 18 percent of NS Power's forecast revenue requirement for each year. While it is inherently difficult to compare electric utilities with different regulatory jurisdictions, geographies and population densities, the benchmarking report completed by ScottMadden and provided as OP-3 states that "NSPI OM&G costs compare favorably to the peer group" and "NSPI is in the first quartile for most metrics despite low usage per customer compared to peers."

Detailed information about OM&G Costs by Group for 2026 and 2027, including primary cost drivers, is contained in **Appendix 7A** with detailed line-by-line operating costs in **Appendix 7C**.

A comparison of test period OM&G expenses to the 2024 test-year GRA compliance filing is contained in **Appendix 7B**.

A Detailed Variance Analysis comparing the 2026-2027 GRA OM&G costs to the 2024 GRA compliance filing, along with a five-year forecast of operating costs, is contained in **Appendix 7D.**

For additional information, please refer to the following Standardized Filing documents:

1.	OP-02	Organization Chart
2.	OP-03 Attachment 1	Benchmarking Report (Scott Madden)
3.	FOR-08	Breakdown of OM&G Expenses
4.	OE-02 – OE-09	OM&G Details
5.	OE-13	Dues and Professional Association Charges

7.2 Benchmarking

NS Power filed comprehensive benchmarking work as part of the 2023-2024 GRA. An updated benchmarking study produced by ScottMadden is provided in standardized filing **OP-03 Attachment 1.** The benchmarking study shows that NS Power's costs are below or in line with electric utility norms, and NS Power performs favourably compared to its peers, generally in the top quartile.

While comparing electric utilities in different Canadian and American jurisdictions can be difficult and has its limitations, because of the differences in company structure, ownership, customer base, asset base, operating geographies and size, the benchmarking analysis by ScottMadden in OP-03 Attachment 1 shows the following:

- NS Power's OM&G as a percentage of retail revenue is first quartile and the third lowest among the peer group studied on a five-year average basis.
- Total OM&G costs per retail customer on a five-year basis are first quartile for NS Power and the second lowest among the peer group, approximately half of the median amount for the peer group.
- NS Power's OM&G costs per retail MWh sold is in the first quartile and fourth lowest among the peer utilities.
- The Transmission OM&G costs per retail MWh sold are the second lowest among peers, significantly below the peer group median.
- The Transmission OM&G per kilometre of transmission line is also second lowest among peers, averaging approximately half of that of the peer utilities.
- Similarly, NS Power's Distribution OM&G per retail customer is first quartile and second lowest among the peer group.
- Distribution OM&G costs per retail MWh sold and per kilometre of distribution line are first quartile and third lowest among peer utilities.

- Overall, NS Power's Production OM&G per MWh generated is first quartile for the peer group and third lowest among utility peers.
- Customer Accounts OM&G per retail customer is first quartile and second lowest among peers.
- Customer Accounts OM&G per retail MWh sold is first quartile, with NS Power fifth lowest among peers.
- Administrative and General costs are also favourable, with NS Power falling significantly below the peer group median.
- Capital Employed metrics are generally at or below the peer group median, with the exception of distribution additions as a percentage of distribution plant. NS Power is below the median for distribution additions as a percentage of depreciation expense.
- NS Power's finance and accounting and supply chain metrics generally compare favourably against peer utilities. Finance and accounting costs as a percentage of revenue are better than the industry median.
- NS Power's Information Technology costs per business entity full-time equivalent employee is significantly below the utility industry median.

7.3 Five-Year Operating Cost Forecast

In this Application, NS Power has included a five-year forecast summary of operating costs in **Appendix 7D**. Multi-year forecasts of operating costs are inherently uncertain. Many factors can affect NS Power's operating costs from year to year, including frequency and severity of storms, scope and timing of plant maintenance, changes in the costs of materials, level of customer growth, load changes, changes to pension expenses, vehicle fuel costs, insurance cost increases, and other market and inflationary changes. **Figure 7-1** shows the estimated costs and percentage increases projected over five years.

Figure 7-1 – Five-Year Operating Cost Forecast

	2026	2027	2028	2029	2030
Operating Costs ($ million)	351.8	357.9	380.0	387.5	385.0
Increase ($ million)		6.1	22.1	7.4	(2.5)
Percentage Change		1.7	6.2	2.0	(0.6)

The following inputs and assumptions were used in the preparation of this forecast:

- Wage increases for both union and non-union employees.
- Inflationary increases of 2 percent annually for non-labour costs.
- Administrative overhead allocated to capital consistent with the Company's established practice consistent with forecast capital program investment levels in those years.
- Timing of thermal unit retirements.
- Storm expenses consistent with five-year average (2020-2024).
- Pension expense figures consistent with those provided by NS Power's actuary and based upon an extrapolation of accounting valuation results as of December 31, 2024. Current service pension expense not included in labour totals $10.1 million in 2028, $13.0 million in 2029 and $16.5 million in 2030.
- The consensus approach to this GRA results in a greater year-over-year increase from 2027 to 2028.

8 DEPRECIATION AND REGULATORY DEFERRALS

8.1 Overview

NS Power is a capital-intensive business that employs a significant asset base used in and in support of generation, transmission, and distribution of electricity. Due to the size and scope of the Company's asset base, NS Power tracks its assets in pools at the mass property or location level. This methodology is standard in the electric utility industry as tracking this significant number of assets on an individual asset basis is not practical and cost prohibitive. NS Power's asset pools are depreciated over a period that approximates their estimated remaining useful lifespan. A fraction of each asset pool's original cost is treated as an expense each year until the asset investment and expected removal costs are fully recovered.

From time to time, the Board allows or directs NS Power to build or acquire an asset or incur some other business expense that is not included in the expenses in the existing rates it permits the Company to charge. The Board may direct NS Power to defer certain charges. When that happens, the deferred charge is considered a regulatory asset, which is an amount the Company will be able to recover in the future. Like any other asset that is not consumed in a single year, it must be depreciated or amortized over time for recovery in rates. This is known as regulatory amortization.

The following sections outline the expenses NS Power seeks to recover through 2026-2027 customer rates for property, plant and equipment and regulatory assets.

For additional information, please refer to the following Standardized Filing documents:

- DA-01 Depreciation Rates
- DA-02 Accumulated Reserve for Depreciation
- DA-03 Amortization Expense
- DA-04 Asset Retirement Obligations (ARO) Reserve

8.2 Depreciation Study

NS Power owns significant assets, referred to as Plant, which were placed into service at different times. The Company is permitted to recover its prudently incurred costs, which include depreciation costs over the estimated useful life of the assets. Depreciation rates are included in customer rates, and the cost of the assets are recovered from customers. NS Power uses a straight-line depreciation methodology, meaning that an asset depreciates each year by the same amount over the estimated useful life of the assets.

The Company's depreciation rates have not been updated by way of a depreciation study since 2011 when intervenors and NS Power entered into a black box settlement agreement which was approved by the Board.[2]

In the 2023/2024 GRA, the Board directed NS Power to complete a depreciation study prior to filing its next GRA. NS Power retained consultant Gannett Fleming to conduct an updated depreciation study, and the Gannett Fleming Report is included as **Appendix 8A**.

The categories of Plant included in the depreciation study are the following:

- Steam Production Plant
- Hydro Production Plant
- Solar Production Plant
- Wind Generation Plant
- Gas Turbine Generation Plant
- Transmission Plant
- Distribution Plant
- General Plant

8.2.1 Depreciation Rates for Assets within the Scope of the DDA

When the NSEB approved NS Power's DDA, it accepted NS Power's proposal that assets determined to be within the scope of the DDA would not be required to be included within the scope of a depreciation study, with the exception of Trenton 5, International Coal Pier, and Steam

[2] NS Power 2010 Depreciation Study, NSEB Order, NSUARB-NSPI-P-891, May 11, 2011.

General assets. While NS Power has included all assets within the depreciation study for information purposes, consistent with the DDA framework, NS Power is not proposing to update the depreciation rates associated with the assets within the scope of the DDA. The assets are as follows:

- Point Aconi
- Trenton (including Units 5 and 6 and Common Plant)
- Point Tupper Marine Terminal
- (Sydney) International Coal Pier
- Steam General Assets

As described in **Appendix 8F**, NS Power is working with the Province and, subject to confirmation of satisfactory credit rating agency treatment, intends to securitize the net book value of the assets within the scope of the DDA as of December 2025.

8.2.2 Decommissioning Costs

A Depreciation Study requires NS Power to estimate the future cost of decommissioning its generation sites, as depreciation rates are generally set to recover the unrecovered decommissioning costs over the estimated remaining useful life of the assets.

There are three decommissioning studies that informed the decommissioning estimates included in the Depreciation Study:

- Hatch Hydro Decommissioning (December 2024) – **Appendix 8B**
- Boreas Hydro Asset Archaeological Costing Study (January 2025) – **Appendix 8C**
- Stantec Remediation Study (August 2024) – **Appendix 8D**

NS Power's proposed depreciation rates have been set using hydro decommissioning estimates based on a partial decommissioning scenario. A summary of Hydro Full and Partial Decommissioning Costs has been included in **Appendix 8E.** The depreciation study also excludes decommissioning costs for Wreck Cove, Tusket and Mersey generating station systems. Please refer to **Section 8.5** below for further discussion on this point.

The scope of Hydro partial decommissioning used the same methodology used in the 2018 Hydro Asset Study. Hydro partial decommissioning estimated costs include removal and site remediation of buildings and structures, turbines, generators and auxiliaries, electrical services, and common services. Hydro partial decommissioning estimated costs do not include removal of structures required for water management such as dams, spillways, and gates.

The Hydro partial decommissioning estimated costs were adjusted based on the escalation drivers provided in the Hatch Hydro Decommissioning Report. In that report, escalation considered such factors as inflation, materials costs, labour costs, benchmarking studies, and actual project costs for similar projects.

8.2.3 Proposed Depreciation Rates

The depreciation rates that were developed as a result of the consensus approach to this GRA and the supporting documentation are included in **Appendix 8G.**

The Depreciation Study proposes depreciation rates which result in annual depreciation expense of $385.2 million when applied to depreciable plant balances as at December 31, 2023. The depreciation rates developed as part of the consensus approach to this GRA result in annual depreciation expense of $365.7 million when applied to depreciable plant balances as at December 31, 2023. The summary table from the Appendix 8G is reproduced below as **Figure 8-1.**

Figure 8-1 – Summary of Depreciation Cost, Accrual and Amounts

Function	GBV- Studied Plant (December 31, 2023) ($)	Accrual Rate	Total Accrual Amount ($)
Steam Production	2,616,967,386	6.47	169,219,037
Hydro Production	614,021,913	2.08	12,801,477
Solar	1,582,854	3.89	61,606
Other Production	492,589,726	4.50	22,182,232
Transmission	1,254,616,801	2.70	33,825,592

Function	GBV- Studied Plant (December 31, 2023) ($)	Accrual Rate	Total Accrual Amount ($)
Distribution	2,137,686,386	3.45	73,717,352
General	740,996,013	7.27	53,887,702
Total	**7,858,461,079**	**4.65**	**365,694,997**

The figures above include annual accruals calculated for all thermal assets, including those within the scope of the DDA. As NS Power is not proposing to increase the depreciation rates for the assets included within the scope of the DDA, the proposed depreciation rates applied to depreciable plant balances as at December 31, 2023 would result in a lower Total Accrual Amount as shown in **Figure 8-2** below.

Figure 8-2 – Summary of Depreciation Costs, Revised using Proposed Depreciation Rates

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

Applying the proposed depreciation rates to forecast monthly balances of depreciable plant throughout the test period results in forecast depreciation and accretion expense of $309.0 million in 2026 and $327.4 million in 2027. However, as NS Power intends to securitize certain asset pools that will be retired prior to 2030, depreciation and accretion expense is further reduced by $26.6 million annually, resulting in totals of $282.4 million in 2026 and $300.8 million in 2027.

8.3 Amortization Accounting for General Plant Assets

The Depreciation Study also proposes the adoption of Amortization Accounting for five General Plant accounts, discussed in Part V of the Gannett Flemming Report, **Appendix 8A**. Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized.

NS Power proposed the adoption of Amortization Accounting for these accounts in the previous Depreciation Study, but use of Amortization Accounting was not adopted as the settlement agreement did not expressly approve the adoption, rather only the rates set under Amortization Accounting methodology were adopted as part of the Settlement Agreement.

If approved as part of this General Rate Application, the Company would adopt Amortization Accounting, which would require the retirement of vintaged asset balances, assumed to be fully depreciated as determined in the Depreciation Study. The lower depreciation as a result of these retirements would be offset by a reserve imbalance amortization charge, as described in Part V of Gannett Flemming's report, **Appendix 8A**. Subsequent to adoption, NS Power would record additions to each of the Accounts in annual vintaged pools, which would be amortized over the specified Amortization Period for that Account, and with the original cost retired at the end of the Amortization Period.

The estimated impact of adopting Amortization Accounting would result in annual incremental Depreciation Expense of $600,000 over the test year period.

8.4 Additions to Plant

In 2026, depreciation and accretion expense is forecast to increase by $2.5 million over the 2024 GRA Compliance Filing. In 2027, depreciation and accretion expense is forecast to increase by $18.4 million from the 2026 forecast amount. These increases result from updated depreciation rates and capital additions to plant in service, as filed in the approved Annual Capital Expenditure Plan (ACE) Programs and other capital expenditures approved by the Board. NS Power's average Gross Book Value (GBV) was $8,160 million in the 2024 GRA Compliance forecast. In the updated test period forecast, the GBV has increased to $8,499 million in 2026 and $8,889 million in 2027.

Since general rates were last set in the 2023-2024 GRA, NS Power's capital expenditures remain focused on maintaining and improving reliability, safely delivering and providing electric service to customers, and meeting the 2030 decarbonization targets in a way that is as cost-effective as possible for customers. The capital outlook for 2026-2027 reflects the Company's best estimate of capital investment over the test year period at a point in time. As detailed in the 2025 ACE Plan submission, the capital investment plan:

- Will provide benefits in communities throughout the province, including reliability focused improvements on the transmission and distribution system and response to reliability challenges arising from increasingly more severe weather.

- Will support NS Power's business priority of safe delivery of electricity service to customers.

- Will continue to support ongoing environmental compliance, such as the maintenance of hydro and wind renewable energy resources, and the continued remediation of PCBs containing equipment and management of asbestos through corresponding recurring capital programs aligned with regulation timelines.

- Is aligned with, and assists in, enabling the Company's compliance with the 80 percent Renewable Electricity Standard and phase-out of coal by 2030.

The capital investment included in the 2026-2027 test period forecast is the estimated amount required to continue delivering on the objectives above and to execute on the Company's five-year reliability plan.

8.5 Hydro

Decommissioning hydro assets is generally far more costly than refurbishing them, yet refurbishing may seem economically disproportionate to the output. This creates a difficult challenge for NS Power's hydroelectric future.

As stated in **Section 8.2.2**, NS Power has excluded the costs of decommissioning the Wreck Cove, Mersey, and Tusket hydroelectric assets from the calculation of the proposed depreciation rates. The estimated future cost to partially decommission these hydro systems is estimated at approximately $550 million, totalling $293 million for Tusket, $228 million for Mersey and $27 million for Wreck Cove.[3] Given the magnitude of these costs and the broad policy, societal, and environmental considerations and factors that would need to be taken into account to decommission such sites, NS Power believes removing these costs from customer rates, at this time, is a reasonable approach to balancing cost recovery and rate pressure for customers; however, NS Power is only proposing to do so to the extent that it does not prejudice its ability to recover such costs in the future should they be prudently incurred.

This decision was based, in part, on the renewable electricity standard requirements to provide 80 percent renewable electricity in the year 2030 and all years beyond, which is of particular relevance Wreck Cove and Mersey, but consideration must also be given to the societal and environmental impacts that would result if these sites were decommissioned. This latter consideration is of particular relevance to Mersey and Tusket. Decommissioning those sites would present significant environmental, archeological and cultural, commercial, and socio-economic challenges that carry significant costs as further discussed below:

- **Environmental Impact**: Decommissioning hydroelectric assets causes significant changes to existing habitats impacting fish, fish passage, flora and fauna, and species at risk. Decommissioning hydroelectric assets also causes changes to shorelines and wetlands, waterflow patterns, and presents requirements for sediment management. At

[3] For context, full decommissioning costs would be estimated at $4.5 billion total, with $0.5 billion for Tusket, $1.9 billion for Mersey and $2.1 billion for Wreck Cove.

Tusket, approximately 5 km^2 of shoreline, that is currently inundated by water would be exposed and at Mersey, at least 50 km^2 of shoreline that is currently inundated by water would be exposed. The Mersey River is the largest drainage system in Nova Scotia, with a watershed area of approximately 3030 km,^{2} while the Tusket watershed area is approximately 3,000 km.^{2} Both fish and terrestrial wildlife habitats have been significantly altered from their initial natural states as a result of the construction of the hydro systems. Following decommissioning, fish and terrestrial wildlife habitats along both the Tusket and Mersey Rivers would need to adapt. Significant re-vegetation programs would also be required. In the case of Mersey, this would, in part, occur within and impact the Kejimkujik National Park.

- **Archeological/Cultural Impact**: Archaeological sites, including potential burial sites, have been identified near, on, or under hydroelectric assets. Decommissioning would require measures to protect known archeological sites, including taking additional protective measures to prevent looting. At Tusket alone, more than 90 archaeological sites would be exposed and at risk of looting, while at Mersey over 230 archaeological sites have been identified down river from Kejimkujik National Park.

- **Commercial Impact**: Decommissioning hydroelectric assets presents changes to local commercial fisheries, tourism/recreational/hospitality-based businesses, and causes a change in property values (if no longer waterfront properties), and property tax revenue. For example, on the Tusket Hydro System alone, a staggering 402 waterfront residential properties would lose their waterfront status and another 71 waterfront residential properties on the Mersey Hydro System. This would have a direct and immediate impact on property values, likely causing a sharp decline. For many homeowners, the allure and premium of owning waterfront property are key to both their quality of life and financial investment. The loss of this crucial feature would not only reduce home values, but it may also make these properties significantly harder to sell or refinance, potentially creating long-term financial hardship for many in the community.

- **Social Impact**: Decommissioning presents changes in shorelines and waterfrontage, access to fresh potable water, and changes to the recreational use of the waterway. In the case of the Tusket Hydro System, a reduction in the water table through decommissioning the Hydro System, would result in effects on residential wells.

In addition to the foregoing, in the case of the Wreck Cove Hydro System, the system plays a critical role in NS Power's ability to meet the reliability standards defined by NERC and NPCC. Wreck Cove is required to help maintain sufficient capacity to serve peak load, as well as additional capacity for the planning reserve margin. Wreck Cove contributes significantly to Operating Reserve requirements, is a black start resource, and assists with providing tie-line regulation. Wreck Cove also provides critical peak load shaving capacity as it can be brought on-line quickly during periods of high load ramping and is important for energy balancing and wind following.

Any decision to decommission the Wreck Cove, Tusket, or Mersey hydroelectric sites would require consideration of a broad range of parties, perspectives, and factors and until that broader discussion has occurred and there is a better understanding of the likelihood of decommissioning, NS Power believes its proposed approach of not including such costs in customer rates, at this time, is a reasonable approach to mitigate rate pressure for customers.

8.6 Regulatory Amortizations

Regulatory amortizations for 2026-2027 are set out in **Figure 8-3** below. Regulatory amortization expense is forecast to be $9.1 million in 2026 and $9.3 million in 2027.

Figure 8-3 – 2026-2027 Regulatory Amortizations ($ Million)

Amortizations	**2026**	**2027**
Non-Standard Meters	2.4	-
Hurricane Fiona Cost Recovery	3.4	3.4
Roseway Hydro Decommissioning Costs	1.0	1.0
Annapolis Tidal Net Book Value	-	2.6
Smart Grid NS Net Book Value	0.3	0.3
GRA and COSS Deferral	1.0	1.0
Total	**8.1**	**8.3**

Non-Standard Meters – Upon completion of the AMI project and determination of the remaining net book value to be amortized, NS Power will complete the expense of the unrecovered cost of meters replaced under the AMI project from 2022-2026. The net book value of these meters will be fully recovered by 2027.

Hurricane Fiona Cost Recovery – Following restoration from Hurricane Fiona, NS Power retired assets damaged by the storm and has deferred recovery of storm restoration costs which resulted in the amortization of approximately $10 million undepreciated capital cost and $24.6 million of OM&G restoration costs, respectively, both of which began amortizing in July 2024 for a period of ten years.[4]

Roseway Hydro Decommissioning Costs – NS Power has applied for the decommissioning of the Roseway Dam and is seeking to amortize the costs associated with the decommissioning over a five-year period, beginning in 2026.[5]

Annapolis Tidal – NS Power has forecast the retirement of the Annapolis Tidal plant in January 2027 with amortization of the unrecovered net book value of this facility over a ten-year period. As a result, there is $2.6 million of regulatory amortization associated with this facility included in the Company's forecast 2027 revenue requirement.

Smart Grid Nova Scotia – The Company has applied to amortize the unrecovered net book value of certain assets in the Smart Grid Nova Scotia Asset Disposition Application[6] on April 4, 2025 over five years.

GRA and COSS Deferral – In its 2023-2024 GRA Decision, the NSEB approved the Company's request to defer and create a regulatory asset associated with the costs for the COSS, Line Loss Study, and Climate Change Adaptation Plan.[7] In addition to those costs, NS Power is seeking approval to include other GRA-related costs in this deferral for inclusion in rates. These costs would consist of NS Power, Intervenor, and NSEB costs required to provide representation and

[4] M11169, NS Power 2022 ACE Plan Distribution Routines D008 Application to Overspend, NSEB Decision, June 27, 2024.
[5] M11556, NS Power Roseway Dam Decommissioning Application, Exhibit N-1, December 20, 2024.
[6] M12178, NS Power Smart Grid Nova Scotia Asset Disposition Application, April 4, 2025.
[7] M10431 decision para. 368.

expert opinions, assist in preparation of/for this GRA, and otherwise participate in these proceedings. The amounts are forecast at $4.0 million and would be recovered on a straight-line basis over the two-year test period. However, in light of reaching a consensus on this GRA with customer representatives and the regulatory efficiencies that are expected to result from this, NS Power has reduced the amortization to recover $2.0 million, rather than $4 million, over the two-year test period.

Deferred Decarbonization Asset – The Board approved the creation of the DDA for the recovery of unrecovered costs associated with generation assets to be retired by 2030 to meet decarbonization legislation,[8] but there are no costs in the DDA account yet. In addition, NS Power is proposing to securitize the net book value of the assets within the scope of the DDA as of December 31, 2025, significantly reducing the amount to be recovered through regulatory amortization of the DDA in the future.

[8] M11220, NS Power Decarbonization Deferral Account Application, NSEB Decision, April 10, 2024.

9 RATE BASE

9.1 Overview

Rate base is the investment made by NS Power in assets required to provide service to customers. Included in rate base are physical assets like power plants, wind turbines, power lines, vehicles, buildings and inventories of fuel and other supplies. It also includes financial assets such as working capital and regulatory assets, net of regulatory liabilities. Regulatory assets are incurred costs which the Board has approved, but which have not yet been recovered through rates, and therefore appear as assets on the Company's balance sheet. Regulatory liabilities reflect amounts recovered for costs that have not yet been incurred that NS Power must either incur in the future or return these funds to customers, resulting in a liability on the Company's balance sheet.

Establishing the rate base is required in the determination of NS Power's revenue requirement as it determines the associated financing costs related to the Company's investment. The financing costs associated with this investment are an important element of NS Power's revenue requirement or cost of providing service to customers.

This Application uses the same Board-approved method for calculating the rate base as in previous General Rate Applications.

In 2026, the average regulated rate base is forecast at $5,582.7 million, which is $30.7 million lower than the 2024 GRA Compliance Filing of $5,613.4. In 2027, forecast average rate base rises to $5,888.6 million, an increase of $305.9 million over 2026. Primary factors contributing to these changes in rate base include:

- Decreased FAM asset balance as compared to 2024 Compliance forecast primarily due to securitization of $500 million related to the increase in the Maritime Link federal loan guarantee and sale of $117 million of the asset balance to Invest Nova Scotia.

- Ongoing capital investment net of depreciation expense collected through customer rates.

- The forecast securitization of thermal asset remaining net book value at December 31, 2025 for assets within the scope of the DDA, totaling $500 million in 2025 and $204 million in 2026.
- Increased forecast fuel supply inventory and increased cash working capital requirements as determined through the lead lag study process.

Figure 9-1 sets out the components of NS Power's average rate base for the 2026 and 2027 test years, calculated in a manner consistent with the NSEB's 2006 Rate Decision and subsequent GRA decisions. Details can be found in Standardized Filing components **RB-02** to **RB-16** of this Application.

Figure 9-1 – 2026-2027 Average Rate Base Components

Average Rate Base	2024C ($M)	2026F ($M)	2027F ($M)
Average capital assets	4,625.5	4,957.8	5,301.3
Average deferred charges & credits	613.2	70.6	69.3
Long-term Income Tax Receivable	132.8	93.3	97.4
Average materials and supplies inventory	170.5	298.4	294.5
Average cash working capital allowance	71.6	162.6	126.1
Total	5,613.4	5,582.7	5,888.6

For additional details and information, please refer to the following standardized filing documents:

- SR-04 Lead-Lag Study
- OP-04 Listing of Assets
- FO-12 Average Rate Base – Assets
- FO-13 Average Rae Base – Charges/Credits
- FO-14 Average Rate Base – Materials/Supplies
- FO-15 Average Rate Base – Working Capital
- RB-01 Plant Continuity Schedule
- RB-02-16 Rate Base Details and Pension Expense
- OR-07 Deferred Cost Recovery Mechanism

9.2 Details of Rate Base

9.2.1 Average Capital Assets

Average capital assets reflect NS Power's forecast average net book value of property, plant, and equipment plus construction work in progress over the 2022-2024 test period. Please refer to **FO-12** of this Application for further details. The Company makes capital additions to utility assets in accordance with the NSEB capital approval processes outside the GRA.

Average capital assets have increased from the 2024 compliance budget due to necessary investments in sustaining and transformational projects. These include improving reliability and customer experience, incorporating more renewable energy, complying with regulations, supporting a growing customer base, and enhancing technology to support grid modernization.
In the electric utility industry, sustaining the asset base through capital re-investment generally results in rate base growth. Capital assets are replaced as needed to enable NS Power to provide reliable service and meet customers' needs. Depending upon the type, assets being replaced may have been in service for many years or decades upon retirement. Replacing capital assets that have been in service for many years with new assets increases the Company's rate base as these new investments will have a higher cost due to inflation that has taken place over the period in which the assets being replaced have been in service. In addition, NS Power is required to make investments in capital assets to enable the Company to comply with regulations and meet the increasing expectations and needs of the Company's expanding customer base. These investments also drive growth in rate base as they require new investment or result in transmission and/or distribution system growth.

NS Power has a mature asset management program and holds itself accountable to make capital investments in an efficient manner to provide value to customers. This is consistent with the data included in the Benchmarking Report provided by ScottMadden in **OP-03 Attachment 1**, that shows NS Power capital investment per customer below the median of its vertically integrated utility peer group.

NS Power's average capital assets will continue to increase over the 2026-2027 test period as the Company makes both sustaining and transformational capital investments. Sustaining capital investment during the test period includes investment in system reliability, investment to meet anticipated customer growth and major re-investment and life extension in the Company's hydro facilities. Transformational capital included in the 2026-2027 capital plan includes investment in assets that will allow NS Power to continue its path to a lower carbon generation mix. These include investments in three 50 MW grid-scale battery sites and new synchronous condensers to enable increased intermittent renewable generation. NS Power has not included investment in the Reliability Tie project, which would construct a second 345 kV AC transmission line between Onslow, NS and Salisbury, NB, in the Company's rate base for the purpose of this application as this investment will be undertaken by Wasoqonatl Transmission Company and costs associated with this investment are proposed to be recovered through a rider as opposed to NS Power's general rates.

NS Power has also developed its Five-Year Reliability Plan which includes investment of $1.3 billion in reliability and resiliency-related projects by 2030.

The increase in NS Power's average capital assets due to capital investment is partially offset by the forecast securitization of the December 2025 net book value of the DDA assets referenced in Section 8.2 (Point Aconi, Trenton, Point Tupper Marine Terminal, Sydney International Coal Pier, and steam general assets). As described in **Appendix 8F** it is anticipated that the Province will issue regulations that will facilitate NS Power's ability to apply to the NSEB for approval to securitize this balance within the year. To maintain the financial health of NS Power, it is key that securitization-related debt is not included in the calculation of NS Power's credit metrics. This will require formal confirmation from NS Power's credit rating agencies. No Canadian investor-owned utility has undertaken a securitization similar to those undertaken by United States investor-owned utilities. As such, it is anticipated that a NS Power securitization will require identifying a finance structure to resolve a variety of issues including, but not limited to, credit rating, trust indenture and tax considerations. Subject to successful credit rating agency processes and the issuance of enabling regulations, NS Power intends to apply to the NSEB for approval for the securitization of approximately $700 million of DDA assets over the GRA period. If such a securitization is delayed such that it cannot be completed in whole or in part by January 1, 2026, NS Power is requesting that depreciation expense and financing costs of these assets be deferred at WACC on an interim basis. Conversely, if it is determined that such a securitization will not be possible, NS Power will amend this filing to include the approximately $700 million of DDA assets in its rate base over the GRA period and inclusion of the associated depreciation expense and financing costs in its applied-for revenue requirement. This would be required to ensure NS Power is provided with the opportunity to recover its prudently incurred costs. Please note that the potential securitization is intended to apply only to the net book value of these assets as of December 2025. Any subsequent sustaining capital investments and operating expenses required while these assets remain used and useful will continue to be included in rate base and/or revenue requirement in the normal course of business.

9.2.2 Average Cash Working Capital Allowance

Cash working capital allowance represents the average amount of capital required above and beyond investments in plant and other separately identified rate base items. These investments bridge the gap between the time expenditures are made and payment in the form of revenue is received. This allowance is determined using a lead/lag study, which analyzes cash flows arising from NS Power's billing, payment, and collection procedures, with the goal of determining the average amount of outstanding working capital.[9] The lead/lag study was carried out by ScottMadden and is contained in **SR-04.**

9.2.3 Average Materials and Supplies Inventory

NS Power has based its fuel and supplies inventory on the projected monthly average for 2026-2027, consistent with the methods used in the 2023-2024 General Rate Application. The inventory consists mainly of coal, biomass, oil, thermal plant materials inventories, and materials inventory required to support maintenance and investment activity on generation facilities and the transmission and distribution system.

The average materials and supply inventory included in the 2026 rate base forecast is $298.4 million, and $294.5 million in 2027.

[9] Refer to FOR-15, which contains Nova Scotia Power's calculations for working capital using the 2012 lead/lag methodology.

9.2.4 Long-Term Income Tax Receivable

NS Power and the Canada Revenue Agency (CRA) remain in a dispute with respect to the timing of certain tax deductions. The ultimate permissibility of the tax deductions is not in dispute; rather, it is the timing of those deductions that is at issue. NS Power must prepay a certain portion of the amount in dispute, as required by CRA.

On November 29, 2019, NS Power filed a Notice of Appeal with the Tax Court of Canada with respect to this dispute. If NS Power is successful in defending its position, all payments including applicable interest will be refunded. If NS Power is unsuccessful in defending any portion of its position, the resulting taxes and applicable interest will be deducted from amounts previously paid, with the difference, if any, either owed to or refunded from, the CRA. The related tax deductions will be available in subsequent years.

Long-term income taxes receivable is increasing over the 2026-2027 GRA test period primarily due to net interest accrued in connection with prior year reassessments and payments made in relation to the timing of certain tax deductions in dispute with the CRA.

9.2.5 Deferred Charges and Credits

NS Power's method for calculating deferred charges and credits conforms to the General Rate Applications since 2007 in which the Company included all components of the deferred charges and credits in the rate base calculation.

Deferred charges, held in approved deferral accounts, represent amounts that NS Power has paid to operate the utility, but which have not yet been expensed. These amounts have not been reflected in customer rates. Such items are useful to better match expenses to the periods in which they provide benefit or in order to promote rate stability and affordability for customers. Examples of deferred charges include costs incurred to execute debt transactions required to operate the business or the difference between fuel revenues collected by NS Power and the actual amount of fuel costs incurred in the FAM.

NS Power forecasts average deferred charges and credits of $70.6 million in 2026 (a decrease of $542.6 million from the 2024 GRA Compliance filing) and $69.3 million in 2027 (a further decrease of $1.3 million from 2026). The primary drivers for the decrease from the 2024 Compliance forecast are the significant reduction in the DDA asset balance due to a Board directed change in timing of when balances are accrued to this account and a reduced FAM asset balance. **Figure 9-2** sets out a summary of NS Power's forecast average deferred charges and credits, and **Figure 9-3** sets out the variances from year to year.

Figure 9-2 – 2026-2027 Forecast Average Deferred Charges and Credits

Deferred Charges & Credits	2024 Compliance ($ Million)	2026 Average ($ Million)	2027 Average ($ Million)
Financing Charges	21.3	22.3	20.5
Pension Charges	97.3	156.9	184.0
FAM Deferral	285.7	(5.2)	(5.5)
SCRR Deferral	-	0.0	0.0
DSM Rider Deferral	(0.7)	0.7	0.4
Other General Charges	40.0	29.6	20.9
Retired Assets (Roseway, Annapolis, Smart Grid NS)	-	5.8	16.1
DDA Asset	319.9	-	-
Cost of Removal Liability	(8.6)	10.6	(7.3)
Asset Retirement Obligation	(127.0)	(146.0)	(153.7)
Deferred Income Taxes	(1.9)	25.3	24.6
Other Deferred Credits	(12.7)	(29.4)	(30.9)
Total	613.2	70.6	69.3

The amounts included in rate base reflect an average of the year's opening and closing balances, consistent with the method applied in previous rate cases.

Figure 9-3 – 2026-2027 Variance in Forecast Average Deferred Charges and Credits

Explanation	2026 vs 2024 ($ Million)	2027 vs 2026 ($ Million)
Financing Charges	1.0	(1.7)
Pension Charges	59.7	27.1
FAM Deferral	(290.9)	(0.3)
Storm Rider Deferral	0.0	0.0
DSM Rider Deferral	1.4	(0.3)
Other General Charges	(10.4)	(8.7)

Explanation	2026 vs 2024 ($ Million)	2027 vs 2026 ($ Million)
Retired Assets (Roseway, Annapolis, Smart Grid NS)	5.8	10.3
DDA Asset	(319.9)	-
Cost of Removal Liability	19.2	(17.9)
Asset Retirement Obligation	(19.0)	(7.7)
Deferred Income Taxes	27.2	(0.7)
Other Deferred Credits	(16.7)	(1.6)
Total	(542.6)	(1.3)

Further explanation of these assets is provided below.

9.2.5.1 Defeasance and Financing Charges

Defeasance costs and deferred financing charges are included in average rate base consistent with previous GRAs. The increase of $1.0 million in the 2026 average as compared to the 2024 GRA compliance forecast is due to additional deferred financing costs associated with bond issuances partially offset by the amortization of these issuance costs over the life of the associated bond and amortization of defeasance deferred charges. Amortization of defeasance over the life of the new debt is in accordance with the Board's 1993 Rate Decision.[10] The reduction of $1.7 million reflects continued amortization of defeasance and issuance costs partially offset by issuance costs added in 2027 associated with the forecast requirement to issue long-term debt in the amount of $250 million during that period.

9.2.5.2 Pension Asset

The average prepaid pension asset in 2026 increases by $59.7 million from the 2024 GRA Compliance Filing budget, resulting in an average prepaid pension asset for 2026 of $156.9 million. In 2027, the average prepaid pension asset increases by $27.1 million to $184.0 million. These increases reflect the difference between the funding provided to NS Power's pension plan, less the amount expensed by NS Power as calculated by the Company's actuary. Pension expense is forecast to be a recovery of $2.1 million in 2026 and a recovery of $0.4 million in 2027.

[10] NSPI 1993 General Rate Application, UARB Decision, NSUARB–NSPI–P-863, April 5, 1993, page 25.

9.2.5.3 Asset Retirement Obligations (ARO)

NS Power recognizes an obligation associated with the retirement of tangible, long-lived assets that it is required to settle. NS Power accrues a liability for the fair value of its obligation to decommission a site when the obligation arises. At that time, a corresponding asset retirement cost is added to the carrying amount of the related asset. NS Power deducts the asset retirement obligation liability from the Company's rate base.

The average ARO liability that reduces rate base is forecast to increase by $19.0 million from the 2024 GRA compliance filing of $127.0 million to $146.0 million in 2026 and by a further $7.7 million in 2027 to $153.7 million.

9.2.5.4 Cost of Removal

The Cost of Removal regulatory account balance represents the non-ARO cost of removal reserve. The cost of removal represents estimated funds received from customers through depreciation rates to cover future forecast non-legally required cost of removal of property, plant and equipment, net of salvage upon retirement. This liability is reduced as costs of removal are incurred. The cost of removal liability balance reduces NS Power's rate base and is expected to increase over the test period as the amount collected through the updated net salvage component of depreciation rates is forecast to be greater than the amount expended to remove assets in-service.

The average cost of removal liability balance in rate base is in an asset position, totalling $10.6 million in 2026. This is forecast to return to a liability position in 2027, increasing by $17.9 million to ($7.3) million.

9.2.5.5 Deferred Income Taxes

Deferred income taxes primarily relate to the FAM deferral and loss carry-forwards arising as a result of fuel under-recoveries. The deferred income taxes associated with the FAM deferral regulatory balance are recorded in the statement of earnings so that any over or under-recovery does not give rise to incremental tax expense (recovery). If deferred tax expense (recovery) was not recorded on the temporary differences related to the FAM deferral, there would be a net tax expense (recovery), such that the after-tax impact of the FAM deferral would not be earnings neutral. As such, deferred tax expense (recovery) is recorded on the FAM regulatory balance to ensure there is no impact to NS Power's earnings.

In 2026, the average deferred income taxes asset balance in rate base is forecast to be $25.3 million, an increase of $27.2 million from 2024 Compliance budget. The average deferred income taxes asset balance decreases by $0.7 million in 2027 to $24.6 million. The change in these balances is primarily due to an increase in the net operating loss carry forward related to regulatory deferrals in 2025, and the utilization of prior year net operating loss carry forwards in 2027.

9.2.5.6 Retired Assets

The retired assets average balance increases in 2026 due to the forecast addition at the end of 2025 of $4.8 million related to the unrecovered decommissioning costs associated with the Roseway Hydro System, with a forecast amortization over five years, and $1.7 million related to the unrecovered net book value of certain retired Smart Grid Nova Scotia assets, also with a forecast amortization over five years. The amortization amount on these assets totals $1.3 million in 2026.

The balance further increases due to the forecast addition of $25.8 million in January 2027 related to the retirement of the Annapolis Tidal assets, with a forecast amortization period of 10 years. This is partially offset by amortization of $3.9 million. Please see

Figure 9-4 below for further details.

Figure 9-4 – Retired Assets Continuity Schedule

($ million)	**2025**	**2026**	**2027**
Beginning Period Balance	**-**	**6.5**	**5.2**
Additions			
Roseway Hydro	4.8	-	-
Smart Grid NS	1.7	-	-
Annapolis Tidal	-	-	25.8
Total Additions	**6.5**	**-**	**25.8**
Amortization			
Roseway Hydro	-	(1.0)	(1.0)
Smart Grid NS	-	(0.3)	(0.3)
Annapolis Tidal	-	-	(2.6)
Total Amortization	**-**	**(1.3)**	**(3.9)**

($ million)	2025	2026	2027
Ending Period Balance	**6.5**	**5.2**	**27.1**
Average Balance	**3.3**	**5.8**	**16.1**

9.2.5.7 Decarbonization Deferral Account (DDA)

Thermal generating assets to be retired before 2030 are included in the DDA so that the unrecovered amounts can be recovered in a way which is flexible and provides a reasonable rate trajectory for customers. In the 2023-2024 GRA, NS Power proposed to move unrecovered amounts from Property, Plant and Equipment to the DDA over the remaining expected life of these assets, resulting in a 2024 expected average balance in this account of $319.9 million. In approving the DDA framework, the Board directed those amounts associated with these assets only be moved to the DDA upon asset retirement. As none of these assets are expected to be retired during the test period, there is no forecast balance in the DDA for 2026 or 2027. In addition, the net book value of these assets as of December 2025 is forecast to be securitized in the GRA test period, significantly reducing the expected remaining costs associated with these assets to be recovered through regulatory amortization of the DDA in the future.

9.3 Maritime Link Capital Applications

In its last GRA, NS Power requested approval of four capital projects associated with transmission upgrades to accommodate energy flowing from the Maritime Link onto and through NS Power's system, and the inclusion of associated costs into rate base.[11] These projects, including their original costs, are as follows:

- CI 43324 - L6513 Rebuild / Upgrade Line Terminals - $18.6 million
- CI 43678 - Separate L8004/L7005 on Canso Crossing Double Circuit Tower - $20.4 million
- CI 45066 - Upgrade L6511 and L7019 Thermal Rating - $2.7 million
- CI 45067 - 67N Onslow 345 KV Node Swap - $3.0 million

[11] M10431, 2022-2024 General Rate Application, p. 64

In its Decision for the 2023-2024 GRA, NS Power understands that the Board approved the capital work orders but deferred allowing the inclusion of the transmission projects into rate base until NS Power could 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-46); 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.[12]

As of the end of Q1 2025, the net economic value of NS Power purchases of additional Nalcor surplus energy and the wheeling tariff revenue has significantly exceeded the combination of depreciation, financing costs, operating costs, and re-dispatch costs for four consecutive quarters. **Figure 9-5** below outlines the total benefits compared to the total costs.

Figure 9-5 – Benefits and Costs of Maritime Link Utilization

	Q2 2024	**Q3 2024**	**Q4 2024**	**Q1 2025**
Total Benefits	$17,171,429	$11,944,554	$13,152,383	$8,701,070
Total Costs	$954,768	$949,158	$943,547	$937,937
Net Benefit	**$16,216,661**	**$10,995,396**	**$12,208,835**	**$7,763,133**

As such, the assets have met the threshold as outlined in the Board's directive and the Company has placed the forecast net book value of the assets into rate base at the beginning of the test period.

For ease of reference, the corresponding capital work orders for each are provided in **Appendices 9A, 9B, 9C and 9D**, respectively. These assets have been depreciating at shareholder expense

[12] M10431, Document 300864, NSEB Decision Letter, Nova Scotia Power 2022-2024 General Rate Application, February 2, 2023, pages 156-157.

since their in-service dates and now that NS Power has met the test set forth by the Board in the previous GRA the assets are now included in the GRA forecast at their forecast net book value.

10 CAPITAL STRUCTURE AND FINANCING

10.1 Overview

NS Power is a capital-intensive business with an obligation to serve its customers. The Company requires a significant amount of capital to invest in generating plants, transmission and distribution equipment and supporting infrastructure to generate and deliver electricity to Nova Scotians. Over the years, NS Power has built many large plants: thermal stations that burn coal, heavy fuel oil, natural gas, and biomass to generate electricity; hydro dams and generators; and more recently, wind turbines and a community solar garden. The Company has built thousands of kilometres of transmission lines and thousands of kilometres of distribution systems, including substations, lines, poles, and all the equipment mounted on them. In addition, the Company has made a required investment in IT and communication infrastructure assets, buildings and vehicles required to support the provision of electricity to customers.

These assets have a life expectancy of many years, and as discussed previously, their cost is recovered from customers over the expected remaining life of the asset pools, over a period of years or decades. NS Power must invest the funds to build this infrastructure in advance. The funds to construct and install these assets come from a combination of two sources: debt and equity.

The financing costs associated with debt (interest expense) and equity (return on common equity) represent a real and significant cost to NS Power for the required investment in the Company's operations.

This section addresses NS Power's need for capital and the manner in which debt and equity operate to provide long-term funding for the Company. For additional information, please refer to the following standardized filing documents:

- OP-01 NS Power / Emera Regulated Annual Reports
- OP-12 Analyst / Bondholder Presentations
- OP-13 Emera Proxy Statement
- OP-15 Quantities / Classes of Shares
- FOR-01 Regulated Statement of Earnings

- FOR-02 Regulated Balance Sheet
- FOR-03 Regulated Statement of Retained Earnings
- FOR-04 Regulated Statement of Cash Flows
- FOR-06 GWh Production and Sales
- FOR-07 Details of Fuel and Purchased Power
- FOR-09 Breakdown of Revenue Requirement and Rate Increase
- FOR-10 Average Capital and Cost of Capital
- FOR-11 Interest Charges
- OR-04 Unregulated Revenues
- OR-06 Sharing Mechanisms
- OE-10-OE-11 Taxes
- OE-12 Foreign Exchange Hedging
- CS-01–CS-03 Capital Structure and Debt/Equity Ratios

NS Power is putting forward evidence from Mr. Jim Coyne and Mr. John Trogonoski of Concentric Energy Advisors about Capital Structure and the Cost of Capital (Concentric Evidence). In recognition of NS Power's characteristics and its financial, operational, and regulatory risks, the Concentric Evidence recommends a ROE of 9.9 percent and a common equity ratio of 45 percent (**Appendix 10A** – Concentric Evidence).[13] However, despite this evidence, NS Power is aware of the need to balance affordability for customers with the financial health of the utility, and is therefore seeking to maintain its current ROE of 9.0 percent and an equity ratio of 40 percent.

10.2 Capital Structure

10.2.1 Debt/Equity Ratio

The capital structure is the combination of the debt and equity used by NS Power to finance its overall operations and rate base. Debt is the long-term and short-term financing provided by commercial lenders and institutional investors, while equity is the investment in the Company

[13] Appendix 10A, Concentric Cost of Capital Evidence at PDF page 86.

provided by investors from the equity capital markets, that is ultimately provided to the Company through its shareholder. In exchange for the debt financing, NS Power must pay interest to its lenders and, similarly, in order to compensate investors for the provision of equity investment, NS Power must provide an appropriate return.

The relationship between the amount of debt and the amount of equity is a significant factor in determining the Company's financing costs. The proportion of debt and equity within the overall capital structure is often referred to as the debt/equity ratio. NS Power currently has an approved equity ratio of 40 percent applied for rate setting purposes. The remaining 60 percent debt is provided by commercial lenders and institutional investors.

Regarding capital structure, the Concentric Evidence found at **Appendix 10A** states:

> … Concentric concludes that an increase in the deemed common equity ratio for NSPI to 45.0 percent would be reasonable. This would place NSPI's common equity ratio at the upper end of electric utilities in Canada, comparable to that of Newfoundland Power (also 45 percent), which is appropriate given the Company's risk profile, but still well below the average of its U.S. peers of 51.1 percent.[14]

Further details on the debt/equity ratio of other North American electric utilities can be found in the Concentric Evidence at **Appendix 10A** Section 6 (PDF pages 56-57).

10.3 Cost of Capital

10.3.1 Debt and Interest

NS Power uses a mix of fixed (long-term) and floating rate (short-term) debt in its capital structure. Long-term interest rates are generally higher, but less volatile than shorter-term interest rates.

Under the exemptive relief described further below, NS Power currently has access to a syndicated revolving bank line of credit. The Company also has an active commercial paper program for up to $800 million, of which the full amount outstanding is backed by the Company's operating credit facility. The amount of commercial paper issued results in an equal amount of its operating credit

[14] Appendix 10A, Concentric Cost of Capital Evidence, at PDF page 85.

facility being considered drawn and unavailable. Commercial Paper is short-term debt issued to investors with maturities from between a day to less than one year.

The predominant rating used by Commercial Paper investors in Canada is provided by the DBRS Morningstar ("DBRS") rating service. NS Power's current rating of BBB (High) is below the minimum credit rating that allows an issuer to participate in this market without exemptive relief. Following credit rating downgrades in Q4 2022, NS Power applied to its securities regulators for exemptive relief to permit it to resume its commercial paper program with its lower credit ratings. On February 9, 2023, the securities regulators granted the requested relief, provided NS Power adheres to the conditions of the order, including maintaining its commercial paper credit ratings at or above their current levels. The exemptive relief will expire no later than February 9, 2028.

Commercial Paper is the lowest-cost form of borrowing for the Company. Maintaining and improving the current DBRS credit rating is imperative to maintain access to this cost-effective form of debt financing. Further information on NS Power's credit ratings and their impact on the Company and customers is discussed in **Section 10.3.3** below.

NS Power plans to continue participating in the Commercial Paper market throughout 2026-2027. The 2026 forecast monthly average short-term rate is in the 3.15 to 3.25 percent range, and the 2027 forecast monthly average short-term rate is 3.25 percent. A further credit rating downgrade would result in the inability to access the Commercial Paper market and significant incremental cost, as NS Power's revolving line of credit rates would typically be more than 100 basis points (one percentage point) higher than Commercial Paper rates on average. In fact, NS Power must strengthen its current credit rating in order to ensure continued access to the commercial paper market after the expiration of the exemptive relief period. See further discussion below in the "Credit Ratings" section.

NS Power has one long-term debt maturity of $40 million within the 2026-2027 test period. The Company forecasts the issuance of $250 million of long-term debt in 2027. Debt funding from Canada Infrastructure Bank and preferred share funding from the Wskijnu'k Mtmo'taqnuow Agency associated with the addition of three 50 MW energy storage sites is also included in the test period forecast. For additional details please refer to **CS 01-CS-03**.

10.3.2 Return on Equity

The ROE represents the amount of net income which the Company can earn and deliver to its investors. It is the return provided for the equity invested. The current NSEB-approved range of ROE is between 8.75 and 9.25 percent, with rates set on 9.0 percent ROE. If this return is less than what investors can obtain from investing their capital in other utilities or businesses with a similar risk profile, then the investor may choose to invest its funds in another company, which provides a higher rate of return.

NS Power relies on external investors (through its shareholder) to invest a sufficient level of capital that will satisfy the commercial lenders and institutional investors that NS Power is financially healthy and stable. A financially healthy and stable utility is one which earns sufficient revenue to pay all its expenses, can meet its obligations to commercial lenders and institutional investors and provides a reasonable rate of return to those investors for the level of risk they take. Please refer to the Concentric Evidence at **Appendix 10A** for the impact of risk on the level of investor returns.[15]

The lower the equity ratio, the higher the rate of debt financing. Lenders are taking on a greater risk if they are required to finance more of the Company's operations, and this results in higher interest rates. Ultimately, these costs are recovered from customers through rates, and if the cost of borrowing increases, customer rates increase. Please refer to **Appendix 10A** for the impact of increased leverage on the Company's risk assessment.[16]

The Concentric Evidence concludes stating that, based on the analysis and modeling undertaken: "[A] reasonable estimate of NSPI's required ROE is 9.9 percent, which is supported by the average result for the North American Electric proxy group."[17]

Further details on the ROE of electric utilities in other jurisdictions can be found in the Concentric Evidence at **Appendix 10A**.[18]

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[15] Appendix 10A, Concentric Cost of Capital Evidence at PDF page 58.
[16] Appendix 10A, Concentric Cost of Capital Evidence at PDF page 59.
[17] Appendix 10A, Concentric Cost of Capital Evidence, at PDF page 86.
[18] Appendix 10A, Concentric Cost of Capital Evidence at PDF page 57.

10.3.3 Credit Ratings

Credit ratings are independent opinions that indicate the relative riskiness of a company's debt securities, and affect a company's cost of capital, as well as its access to capital. All other factors being equal, the higher the credit rating, the lower the cost of borrowed funds.

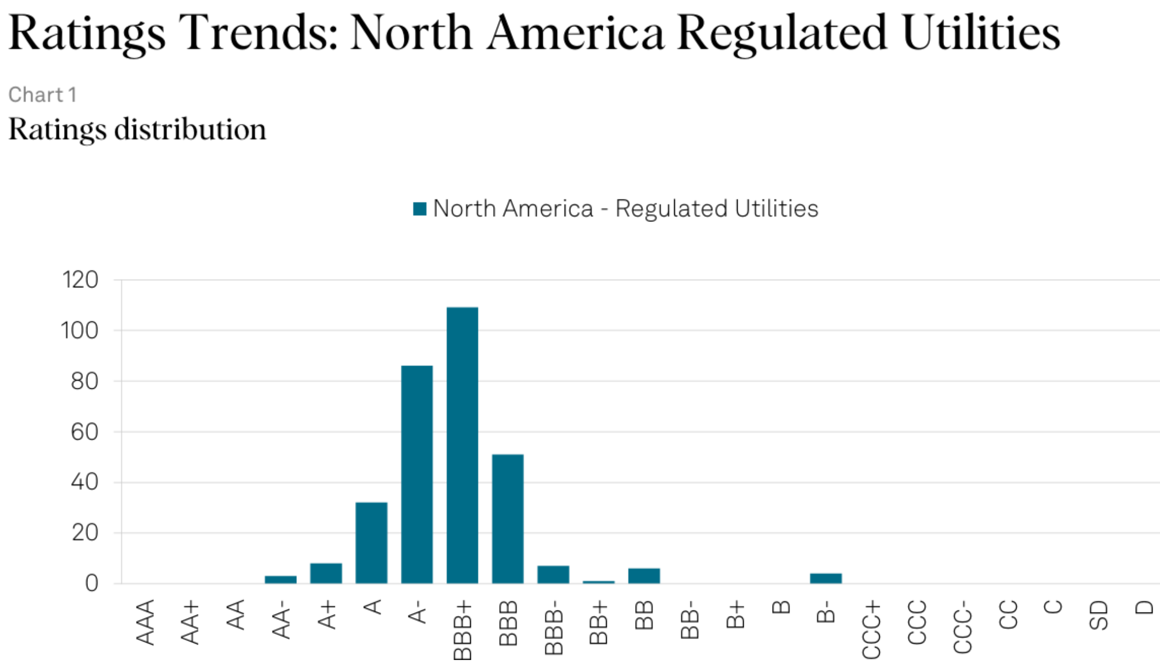
Given the capital-intensive nature of the utility industry, it is critical that utilities maintain strong credit ratings sufficiently above the investment grade threshold to maintain uninterrupted access to capital, and to provide buffer against unanticipated major events such as storms. Maintaining unimpeded access to the capital markets is particularly important for a utility like NS Power which has an obligation to its customers to finance significant capital investments on an annual basis, such as investments associated with the five-year reliability plan.

Companies with lower credit ratings have greater difficulty raising funds in any market, but especially in times of economic uncertainty, credit crunches, or during periods when large volumes of government and higher-grade corporate debt are being sold. As such, it is essential that NS Power maintain credit ratings that are competitive with its peers, particularly given the investments required to be made as the Company transitions away from fossil fuels to clean energy.

NS Power's senior unsecured debt is currently rated BBB- with a Stable Outlook by S&P Global ("S&P") and BBB (high) with a Stable Trend by DBRS. Per **Figure 10-1**, at present, the median S&P rating for the North American utility industry is BBB+, or two notches higher than NS Power's rating. NS Power's BBB- rating is S&P's lowest investment grade credit rating and puts NS Power in the bottom ten percent of the approximately 250 North American regulated utilities S&P rates. Further, S&P rates Nova Scotia as one of the three least credit supportive jurisdictions in North America.[19] NS Power's standalone S&P credit rating is non-investment grade (BB+). It is only by virtue of being a subsidiary of Emera that NS Power receives a one-notch positive adjustment to its credit rating to achieve its BBB- investment grade rating.

[19] North American Regulatory Jurisdictions Update – S&P February 2025

Figure 10-1 – S&P Global North American Regulated Utilities Ratings Distribution[20]



Credit ratings are determined based on an assessment of both business risk and financial risk. The key metric considered from a financial risk perspective is the percentage of cash flow-to-debt (referred to as Funds from Operations ("FFO") to debt by S&P). In order to maintain NS Power's current credit rating, the Company must not experience cash flow to debt of less than 10 percent on a sustained basis. The DBRS cash flow to-debt and S&P FFO-to-debt metric ranges for NS Power's credit ratings prior to the 2023-2024 GRA are 12.5-17.5 percent and 13-23 percent, respectively. The test period forecast results in NS Power's credit metrics returning to levels required for ratings of BBB+ by S&P and A (low) by DBRS by the end of 2027, potentially representing a path to a future credit rating upgrade.

As illustrated in **Figure 10-2** and **Figure 10-3**, NS Power is forecasting to be above the 10 percent requirement to maintain its current credit ratings and returning to levels more aligned with ratings of BBB+ by S&P and A (low) by DBRS by the end of 2027. However, this forecast assumes approval of the rates requested in this Application and a successful securitization of the net book value of the thermal assets. Absent an increase in general rates and successful securitization, NS

[20] S&P Global Ratings, Industry Credit Outlook 2025 – North America Regulated Utilities, January 2025.

Power forecasts that the S&P and DBRS metrics would deteriorate and be below the minimum 10 percent cash flow to debt threshold by 2027. This could result in NS Power no longer having access to the commercial paper market and would have other negative implications for the Company's credit ratings, borrowing costs, required return and therefore, cost of equity and access to capital. The requested rate relief would serve to return these key metrics over time to a level more in line with historical results and provide support for the Company's continued access to the commercial paper market and potentially future credit upgrades.

Figure 10-2 – 2017-2027 FFO/Total Adjusted Debt (S&P Global)

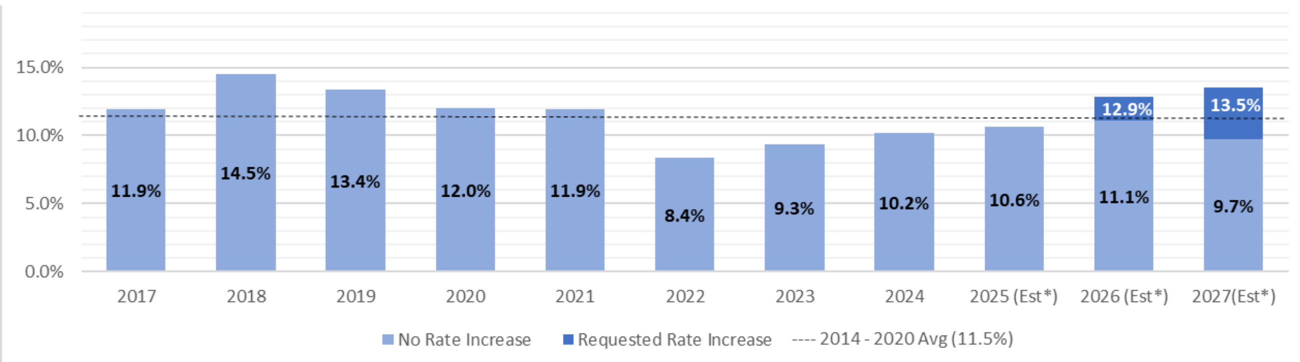
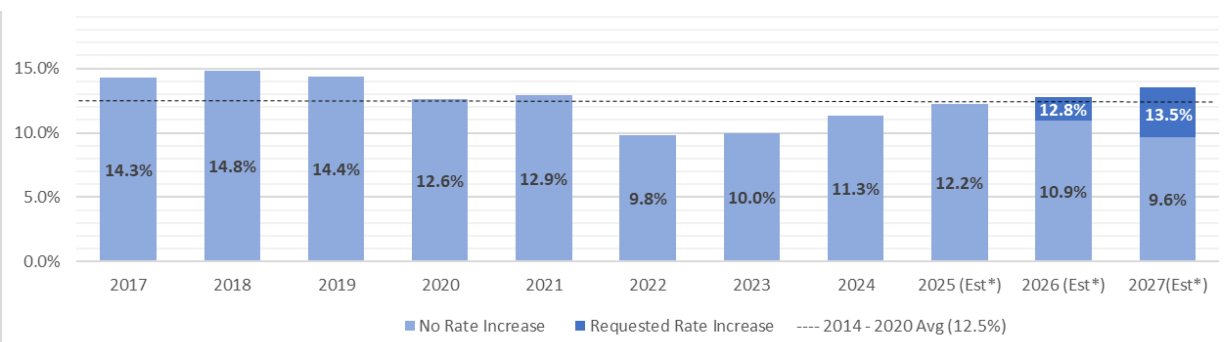


Figure 10-3 – 2017-2027 CFFO/Total Adjusted Debt (DBRS)



A comparison of NS Power's 2023 S&P credit metrics relative to North American peers can be found in **Appendix 10A.**

10.4 Requested Capital Structure and Cost of Capital

It is a well-established regulatory principle and is codified in the *Public Utilities Act* (PUA) that NS Power's approved Capital Structure and Cost of Capital must be sufficient to allow the Company an opportunity to recover the costs of the capital it employs to provide electrical service to its customers. This principle provides the basis for a utility's financial health and stability and, in the present circumstances, adherence to it will assist NS Power in creating a path to potentially improve its current credit ratings, which are critical to allow for uninterrupted access to capital markets to finance capital spending, manage unforeseen events, and continue to provide safe and reliable service throughout the electricity system transformation.

As previously discussed, in recognition of NS Power's characteristics and its financial, operational, and regulatory risks, the Concentric Evidence recommends a ROE of 9.9 percent and a common equity ratio of 45 percent (**Appendix 10A** – Concentric Evidence).[21] However, despite this evidence, NS Power is aware of the need to balance affordability for customers with the financial health of the utility, and is therefore seeking to maintain its current ROE of 9.0 percent and an equity ratio of 40 percent.

The Concentric recommendation assumes that the Storm Cost Recovery Rider being requested as part of this GRA is approved to bring NS Power's risk level more in line with the proxy group utilities.[22]

For ease of reference, the general conclusions of the Concentric Evidence are reproduced below:

> Concentric concludes that NSPI has greater business risk compared to other Canadian investor-owned electric utilities. In particular, factors contributing to this greater business risk include: 1) NSPI's ownership of regulated generation assets, and the need to transition from coal and gas-fired generation toward more renewable resources by 2030; 2) NSPI's lack of protection against volumetric risks; 3) NSPI's exposure to severe weather conditions, especially hurricanes and ice storms; 4) the aggressive DSM targets in the province; and 5) the risk of political intervention in the regulatory process in Nova Scotia. While the regulatory framework in Nova Scotia is generally supportive of maintaining NSPI's credit

[21] Appendix 10A, Concentric Cost of Capital Evidence at PDF pages 85-87.
[22] Appendix 10A, Concentric Cost of Capital Evidence, PDF page 79.

> quality, there are certain aspects of the operating environment where the Company has greater business risk than other Canadian investor-owned electric utilities.[23]

The Concentric Evidence continues, stating:

> The average of all three methods for the North American Electric proxy group is 9.9 percent, within the range of 9.29 percent to 10.32 percent. Based on this analysis, we believe a reasonable estimate of NSPI's required ROE is 9.9 percent, which is supported by the average result for the North American Electric proxy group. However, NSPI is requesting to maintain its existing authorized ROE of 9.0 percent in order to mitigate the rate impact on customers of this GRA filing. The average for the Canadian proxy group, several of which have unregulated business activities and many of which do not own regulated generation and several of which have significant U.S. operations, is 9.6 percent.
>
> NSPI is proposing to continue its deemed equity ratio of 40.0 percent. This request is reasonable, if not conservative, given the business and financial risks of NSPI, which distinguish the Company from other electric utilities in Canada and the U.S. As discussed previously in this report, there is an inter-relationship between the authorized ROE and the deemed capital structure. That is, firms with lower common equity ratios require higher rates of return to compensate shareholders for the additional financial risks. If the deemed common equity ratio for NSPI is maintained at the current level of 40.0 percent, our ROE recommendation of 9.9 percent is understated based on market data for risk comparable companies in both Canada and the U.S., and more so at the Company's requested ROE of 9.0 percent.[24]

NS Power supports the Concentric Evidence and agrees that the requested ROE and common equity ratio are conservative, given the Company's risk profile. However, as previously stated, NS Power understands the cost pressures that already exist in the context of this proceeding and is therefore requesting a ROE band of 8.75 to 9.25 percent with the retention of its current 9.0 percent for purposes of rate setting and a common equity ratio of 40 percent.

The 40 percent common equity ratio put forward in the Concentric Evidence represents an equity ratio that NS Power forecasts would return the Company to credit metrics levels more aligned with ratings of BBB+ by S&P and A (low) by DBRS by the end of 2027

[23] Appendix 10A, Concentric Cost of Capital Evidence at PDF page 79.
[24] Appendix 10A, Concentric Cost of Capital Evidence, PDF pages 86-87.

NS Power views its request in relation to ROE and common equity ratio as an appropriate compromise with the Concentric Evidence that seeks to align the interests of customers and the Company.

Maintaining the current approved common equity ratio is particularly important to maintaining NS Power's current credit ratings given the significant capital investments required over the remainder of the decade. Although NS Power earns AFUDC during the construction phase of projects, AFUDC is non-cash; it contributes to NS Power's earnings, but it does not contribute to NS Power's cash flow. As such, significant capital projects result in a deterioration in credit metrics during construction, as debt increases to fund the debt component of the capital structure, with no corresponding increase in cash flow until the project is placed in service. Therefore, the increase in the common equity ratio is imperative to ensure NS Power improves its current credit ratings such that it has the financial integrity to attract the capital necessary to fund these transformational capital investments.

Figure 10-4 below sets out the proposed Capital Structure and ROE for rate setting purposes in each of 2026 and 2027.

Figure 10-4 – Summary of Requested Cost of Capital

	2026-2027
Debt / Equity ratio	60.0 / 40.0
ROE (percent)	9.0

11 REVENUE REQUIREMENT

11.1 Overview

Broadly speaking, revenue requirement is the amount of revenue which NS Power needs to collect in a test year in order to cover the cost of providing service to its customers and providing a fair return for NS Power's shareholder. Revenue requirement includes various categories of costs to be recovered from customers. Once the amounts are determined in each category, it is necessary to determine what the anticipated sales will be for the customers in each class, and then apportion costs to the customer classes using COSS methodology. If the revenue requirement is greater than the forecast revenue, there is a shortfall which must be recovered by increasing rates.

11.2 Revenue Requirement Categories

Revenue requirement is the sum of amounts necessary to be recovered in each test year in the following fuel and non-fuel categories:

- Fuel and purchased power, including solid fuel costs, natural gas, oil, renewable energy costs, fuel transportation costs, import costs, hedging gains/losses, foreign exchange costs and GHG emission compliance program costs;
- OM&G costs including labour, materials, contracts, pension costs, insurance, memberships dues, subscription costs, office supplies, travel and meals expense;
- Third-party DSM costs;
- Depreciation and Accretion expense on capital assets;
- Regulatory Amortization Expense, including FAM expense;
- Taxes including Income Taxes and Grants in Lieu of Property Taxes;
- Interest and Other Expenses; and
- Return on equity.

Details of these cost categories can be found in **Section 5** and **Sections 7 through 10** of this Application and are outlined below in **Figure 11-1**.

Figure 11-1 2026-2027 Breakdown of Forecast Revenue Requirement by Category

Category	**2026 ($ Million)**	**2027 ($ Million)**
Fuel & Purchased Power	$918.6	$918.4
OM&G	351.8	357.9
Demand Side Management Expense	63.8	63.8
Depreciation and Accretion	282.4	300.8
Taxes (including grants-in-lieu of property taxes)	29.7	56.1
Regulatory Amortization (including FAM expense)	16.8	(1.8)
Interest and Other Expenses (including AFUDC and FAM interest)	118.5	130.0
Return on Equity	201.0	212.0
Revenue Requirement	1,982.7	2,037.2
Other Revenue	45.7	46.9
Revenue Requirement from Electric Rates	1,937.0	1,990.2

On June 20, 2024, Bill C-59, "an Act to implement certain provisions of the fall economic statement tabled in Parliament on November 21, 2023 and certain provisions of the budget tabled in Parliament on March 28, 2023" was enacted. Bill C-59 includes the excessive interest and financing expenses limitation ("EIFEL") regime, which is effective January 1, 2024. EIFEL applies to limit a company's net interest and financing expense deduction to no more than 30 percent of earnings before interest, income taxes, depreciation, and amortization for tax purposes. Any denied interest and financing expenses under the EIFEL regime can be carried forward indefinitely.

On August 15, 2025, the Canadian federal government released an updated version of the EIFEL rules which included an exemption for regulated utilities. In determining its revenue requirement for the 2026-2027 test period, NS Power has assumed the exemption for regulated utilities will be enacted. If the exemption is not enacted, NS Power estimates the potential incremental tax expense over the GRA period to be approximately $7.0 million. As such, NS Power requests the ability to create a deferral to allow it to recover this incremental tax expense in the future should the exemption not be enacted (EIFEL Deferral).

NS Power has forecast costs to be removed from its revenue requirement, totaling $1.6 million in 2026 and $4.5 million in 2027, due to the transition of some current NS Power responsibilities to the NSIESO. The forecast assumes this will occur in a phased approach with a January 1, 2026 transition of responsibilities for generation interconnection requests and system planning activities and a January 1, 2027 transition of Control Centre responsibilities for the day-to-day operations of the transmission system. The timing of this transition is largely out of NS Power's control and will continue to evolve over 2025 as NSIESO Management is appointed and a transition plan is refined. NS Power plans to apply to the NSEB for recovery or refund of the difference in actual operating expense, as compared to forecast, associated with the NSIESO transition once it is complete.

12 COST OF SERVICE

NS Power is applying for both fuel rate increases and non-fuel rate increases. The proposed Cost-of-Service Study (COSS) methodology is as set out in **Appendix 12A**, for which the Company seeks approval. The proposed COSS methodology is applied to both categories of rate increases. This section addresses both the fuel-related and non-fuel related COSS items.

While NS Power and the Customer Representatives have consensus on using the COSS methodology as set out in Appendix 12A and SR-01 Attachments 2, 3, 5, and 6 for the 2026-2027 GRA, the Parties are in agreement that the use of the Minimum System methodology after the 2026-2027 test period will be subject to a future proceeding and determination by the Board, for which an application will be made in 2026 and in which parties are free to take any position they so choose. Similarly, the Parties are in agreement that:

- In any proceeding to determine rates for PHP after the 2026-2027 test period, Parties may make submissions regarding the extent to which PHP is to be responsible for any costs of the High Voltage transmission system; and
- The appropriate apportionment of assessment costs from the Maritime Link as between generation and transmission will remain open to be addressed as Parties see fit in any proceeding to determine rates after the 2026-2027 test period.

12.1 Overview

A GRA has two basic steps:

- First, the Company must determine the revenue requirement: how much it will cost to produce and deliver electricity to meet the electricity requirements of customers in the province, using the least-cost method, while complying with safety, reliability and environmental standards, and allowing a just and reasonable rate of return on the rate base used to provide electricity to customers.
- Second, the Company must establish just and reasonable rates that recover the revenue requirement. NS Power will determine how much of this total revenue requirement should

come from each customer class, what pricing mechanism (e.g. customer charge, energy, or demand) should be used, and the time period for recovery. Traditionally, the revenue requirement is recovered through general rates over a single test year, but in recent years and in this application NS Power has employed the use of a multi-year test year in order to provide smoothing of rates and rate stability for customers.

The first step is addressed in the preceding sections of this Application. The following sections deal with the second step. Further details can be found in **SR-01 Attachments 1(a) and (c).**

There are many factors which influence and contribute to the cost of providing electricity to different customer classes.

To allocate costs, NS Power has applied the COSS methodology as proposed in **Appendix 12A**. This is the process by which the Company calculates the portion of each cost that should be borne by each customer class.

Each of the two GRA test years is treated separately using the proposed COSS methodology described in **Appendix 12A**. The costs allocated in the COSS reflect the annual revenue requirements set forth in the financial tables and discussed in **Section 11**, but they do not include deferred amounts under the FAM or DSM Rider. Both the FAM and DSM Riders are calculated outside of the COSS and have annual proceedings to establish those riders.

Additional information is included in the following standardized filing documents as well as the COSS, COSS Procedures, and Fuel and Purchased Power-Related COSS Methodology in **Appendix 12A**:

- SR-01 Cost of Service Study
    - Attachment 1:
        a. Cost of Service Procedures
        b. Determination of Revenue Responsibilities by Rate Class
        c. Fuel and Purchased Power Related Cost of Service Methodology
        d. Unmetered Services Pricing
        e. Open Access Transmission Tariff (OATT) Updates

- Attachment 2 2026 COSS (Partially Confidential)
- Attachment 3 2027 COSS (Partially Confidential)
- Attachment 4 Interruptible Credit Calculations
- Attachment 5 2026 Base Cost of Fuel (BCF) Allocation (Partially Confidential)
- Attachment 6 2027 BCF Allocation (Partially Confidential)
- Attachment 7 Revenue to Cost (R/C) Ratios
- Attachment 8 Rates by Component Tables
- Attachment 9 2026 Unmetered Calculations
- Attachment 10 2027 Unmetered Calculations
- Attachment 11 2026 OATT Rate Development
- Attachment 12 2026 OATT Ancillary Service Costs
- Attachment 13 2027 OATT Rate Development
- Attachment 14 2027 OATT Ancillary Service Costs
- Attachment 15 2026-2027 Distribution Tariff Calculations

- OP-10 Customers by Rate Class
- OP-11 Hydro Quebec (Canadian Electricity Rates) Report
- OR-01 Proof of Revenues
- OR-02 Miscellaneous Revenues

12.2 COSS Commitments and Directives

Following the 2023-2024 GRA, the NSEB accepted the provisions of the Settlement Agreement[25] and directed NS Power to file an updated COSS and Line Loss by the end of December 2025 or before filing the next GRA, whichever was sooner. At the end of 2023, NS Power retained Elenchus Research Associates Inc. (Elenchus) as its expert consultant on the COSS, and stakeholder sessions commenced on January 18, 2024. Throughout 2024, technical conferences were held to provide in-depth educational sessions on the current COSS treatment at NS Power and identify the primary issues to be resolved as part of the formal regulatory process, areas

[25] M10431, Exhibit N-155, Schedule "A" Terms of Settlement, GRA Element "Line Loss Study and COSS," page 6 (PDF page 10). November 24, 2022

requiring additional examination, and areas of consensus and disagreement among parties. For the proposed COSS, please refer to **Appendix 12A**.

12.3 Fuel-Related COSS

A traditional BCF Application considers setting BCF rates for a test period based on the fuel cost requirement in accordance with COSS methodology and as prescribed in the FAM Plan of Administration. Consistent with the way fuel costs are treated from a COSS perspective in a GRA, the cost responsibility for fuel costs forecast for each test year is allocated among rate classes using the procedural steps outlined in section 3.0 of the revised POA. As the Company is proposing changes to the COSS as a result of the stakeholder engagement the Company has updated the FAM POA as can be seen in **Appendix 6B**. For details on fuel-related cost allocation calculations in years 2026 and 2027 please refer to **SR-01 Attachments 5 and 6**.

12.4 PHP COSS Treatment

NS Power anticipates filing an application for approval of a new above-the-line (ATL) Tariff applicable to PHP and PHP has committed to take service under the ATL tariff effective January 1, 2026, or such later date as determined by the Board, whether on a permanent or interim basis, subject to satisfactory resolution of the ADC and tariff processes. As such, PHP has been treated as an ATL customer in the 2026-2027 COSS. As part of the tariff application the Company expects the provision of ADC service to be proposed as a rider to this new ATL tariff. Any Board-approved payments to PHP for ADC services are expected to be recovered from ATL customers.

PHP's ATL treatment also includes an interruptible credit, the dollar value of which is to be the same as the credit provided to Large Industrial Interruptible Rider (LIIR) customers. In addition, PHP's ATL treatment includes the value of priority interruption service provided, if any. For the purpose of modelling, the value of priority interruption service has been applied as a 10 percent premium to the LIIR credit.

To address potential revenue variances arising from differences between the Board-approved tariff and the assumptions included in the GRA COSS, NS Power is requesting approval for a deferral account (PHP Deferral). This account would apply in the following scenarios:

1. the Board's decision on the PHP tariff or ADC rider differs from the assumptions in the GRA;

2. the tariff is not available for PHP to take service under it as of January 1, 2026; or

3. PHP determines the outcome of the ADC and tariff processes is not satisfactory.

13 ANY RESULTING COSTS OR REFUNDS WOULD BE ALLOCATED TO ATL CUSTOMERS FOR RECOVERY IN A FUTURE PROCEEDING. RATE DESIGN

13.1 Overview

In the 2023/2024 GRA, NS Power introduced or updated several aspects of its rate design, including creation of new tariffs or programs. In this Application, NS Power is not proposing to introduce new concepts or materially modify any of its rate design. Proposed changes and the adoption of the familiar concept of the AMI Opt-out Fee are discussed in this **Section 13**.

13.2 Update to Domestic Service and Small General Customer Charges

In the 2023-2024 GRA, NS Power proposed to increase the customer charge for Domestic Service and Small General customer classes to better align with rates which reflect the actual costs to serve. By way of the settlement agreement and subsequent Board order approving the agreement, the proposed increases were implemented at 75 percent of the amounts proposed.

In this GRA, NS Power proposes to increase the customer charges of the Domestic and Small General Rate classes in the same proportion as the increases in the smoothed non-fuel cost revenues for those customer classes as set out in **Figure 13-1**. The proposed increases are close to 8 percent per year for both rate classes. If the customer charges were to be set directly based on changes in the customer-related costs from the 2026-2027 COSS, they would show about a 50 percent

increase in 2026 followed by a minor a single digit increase in 2027.

Figure 13-1 – Proposed Increases to Customer Charges

Customer Class	Current Rate ($)	Proposed Rate ($) 2026	Proposed Rate ($) 2027
Domestic Service	19.17	20.24	21.38
Small General	21.28	22.16	23.07

13.3 Update to Interruptible Credit

The Large Industrial Interruptible Rider (LIIR) provides LIIR customers with the opportunity to reduce their cost of electricity by agreeing to accept non-firm service from the utility. The credit applicable to this service is applied to Billed Demand and based on the avoided cost of a combustion turbine. For this GRA the Company has updated the Interruptible Credit based on current costs. The credit is proposed to be increased from $7.486/kVA in 2025 to $7.638/kVA in 2026 and to $7.667/kVA in 2027. Support for the Company's update is provided in **SR-01 Attachment 4**.

13.4 Treatment of Fuel Costs

As part of this GRA, the Company is seeking to update the BCF in the 2026 and 2027 test years. Nova Scotia Power is adjusting the BCF rates in 2026 and 2027 to facilitate smoothing the overall rate impact for customers.

The FAM POA requires the BCF to be reset every two years, as part of a GRA, or as directed by legislation or the NSEB. The changes to the BCF are reflected in customer rates and are applied to customer classes in a manner consistent with the proposed COSS.

13.5 DSM Rider

In the 2023-2024 GRA, the NSEB approved NS Power's application for a DSM Rider. The DSM costs are billed as part of the energy charge on customers' bills. Since the GRA, the NSEB has approved the DSM Rider for 2024 and 2025. NS Power proposes to continue recovering the DSM program costs through the rider.

In 2025, the Nova Scotia Government introduced legislation which, among other things, extends the existing DSM Supply Agreement between EfficiencyOne (E1) and NS Power by one year, capping the amount recoverable at $63.75 million.[26] E1 will file its five-year DSM Supply Agreement application in 2026 for DSM program costs effective between 2027 and 2031. For the purposes of this GRA application, NS Power is not proposing changes to the DSM rider amounts for 2026 or 2027. However, NS Power is proposing changes to how the Balance Adjustment (BA) is calculated. Specifically, the BA will include the annual volume variance adjustment calculated by class for the difference between the actual revenues billed through the DSM Program

[26] *Agriculture, Energy and Natural Resources Act,* S.N.S. 2025, c. 4, s. 20.

Post Recovery and the forecast revenues for the previous calendar yar. This component will be applied on a two-year lag. The BA will also include an End of Approved DSM Term Adjustment which trues up the differences by class between the approved and actual spending over the most recent DSM Term (period governing the supply agreement). That amount will be calculated in the first year of the next DSM term and will be applied over the four following years of the DSM term. The BA will reflect the annual volume variance adjustment each year and the DSM Term adjustment after the conclusion of each term.

NS Power will make its 2026 DSM Rider application in accordance with current practice. Per COSS, 100 percent of the DSM costs will be allocated to classes in accordance with DSM program spending.

13.6 Storm Cost Recovery Rider

In the Board's 2023-2024 GRA Decision, it approved the Storm Cost Recovery Rider (SCRR) on a three-year pilot basis, providing for recovery of OM&G restoration costs for Level 3 and 4 storms in the years 2023, 2024 and 2025. This approval was consistent with what had been agreed to by the signatories of the 2023-2024 GRA Settlement Agreement.

As part of this GRA, NS Power is requesting that the Board approve the SCRR as a continuation of pilot for the 2026-2027 GRA test years, such that Level 3 and 4 storm costs in those two years are eligible for the SCRR.

One of the primary concerns regarding the SCRR raised by customer advocates and other parties during the 2023-2024 GRA process was the asymmetrical nature of the SCRR. The asymmetric nature of the current SCRR allows for NS Power to apply to recover the Level 3 and 4 storm costs it incurs above those amounts included the approved revenue requirement, but it does not provide a mechanism that would enable money to be returned to customers if the forecast amounts included in revenue requirement are not fully spent.

In the context of the 2023-2024 GRA, this concern was addressed by the three-year pilot period as well as the mitigating impact of the PUA amendments. As a result, the asymmetric SCRR was approved on a three-year pilot basis. However, these factors would not have the same mitigating effect for a permanent SCRR on a go-forward basis and, as such, NS Power believes it is important to address the concern and ensure the SCRR effectively and equitably addresses the volatility created by severe weather events in the costs to serve customers.

As such, while NS Power is applying for a continuation of the SCRR pilot, it is also asking that the SCRR be in place on a symmetrical basis for 2026 and 2027, which would allow recovery of Level 3 and 4 storm OM&G restoration costs above those included in revenue requirement or for any underspend of such costs to be returned to customers, in each year.

The key elements of the proposed permanent SCRR are the same as what was approved in the in the 2023-2024 GRA, but with the added symmetrical component:

- Forecast Level 3 and 4 storm costs will be included in revenue requirement and base rates.
- Actual Level 3 and 4 storm costs will be tracked each year, and NS Power will file a report by April 1 of each year comparing the actual storm costs with those in customer rates.
- If the actual Level 3 and 4 storm costs do not exceed amounts in base rates, NS Power will track any underspend in a SCRR Customer Account where any underspend will be accumulated until a threshold amount of $2.5 million is reached or a balance has been held for three consecutive years, upon which time NS Power will make an application to return the underspend amount plus any interest to customers. If the actual Level 3 and 4 storm costs exceed the amounts in base rates, NS Power may apply for the Storm Rider to be applied to recover the shortfall effective January 1 of the following year and/or draw down the SCRR Customer Account.
- NS Power will endeavour to file the SCRR application by the end of April each year.
- Non-capital preparation, response and restoration-related costs for Level 3 and 4 storms will be eligible for inclusion in the SCRR, including:
    - Storm preparedness (including crew staging and related logistics);

- Incremental wages, benefits and overtime pay related to storm recovery for NS Power employees;
- Costs of external service providers and mutual aid utilities hired during restoration efforts;
- Materials, supplies, and any associated expenses used to repair damaged assets and equipment;
- Other recoverable expenses, including extra costs for temporary repairs and to expedite permanent repair of damaged property and expenses incurred for providing services to customers whose electric service has been interrupted;
- Eligible storm costs to be recovered through the SCRR will not exceed 2 percent of NS Power's forecast retail revenues; any costs exceeding the 2 percent cap will be deferred to the SCRR the next year; and
- The costs of financing the deferral or return will be calculated at NS Power's approved Weighted Average Cost of Capital and added to the deferral balance.

A copy of the proposed rider is included in **PR-01 Attachment 1V and 2V**.

NS Power proposes the base rate allowances for storm restoration OM&G costs during the GRA period as set out in **Figure 13-2** below.

Figure 13-2 – Storm Restoration OM&G Costs (Levels 1-4)

	Level 1 & 2 ($ million)	Level 3 & 4 ($ million)
2026	9.6	10.1
2027	9.8	10.3

In its 2023-2024 GRA Decision, the NSEB stated that it considered a formalized Climate Adaptation Plan to be useful in demonstrating the prudency of storm restoration costs in SCRR applications and would engender confidence in such a rider if NS Power were to seek to implement one on a permanent basis.[27] Therefore, the Climate Adaptation Plan and Wildfire Mitigation Guide are attached as **Appendices 3B and 3C**.

13.7 Non-Standard Meter Service (AMI) Opt-Out Fee

In January 2022, the Company filed its GRA which included a proposed AMI opt-out charge of $3.67 per month for customers whose meters are currently read bi-monthly, and $22.01 per month for demand customers whose meters will continue to be read monthly. Although NS Power's GRA Settlement Agreement[28] included support from regulatory stakeholders for the proposed AMI opt-out fee, the Board did not approve the proposed AMI opt-out fee in its February 3, 2023 Decision. However, the Board Decision provided general direction, which the Company has addressed in **Appendix 13B**.

In this Application, NS Power proposes a monthly opt-out charge according to the schedule outlined in **Figure 13-3**.

Figure 13-3 – Proposed Schedule of AMI Opt-out Fee Monthly Charges for 2026 and 2027

Standard Customer Meter Read Frequency	Proposed Opt-out Customer Meter Read Frequency	Proposed Opt-out Charge	
		in 2026	in 2027
Bi-monthly (6 times per year)	Semi-annually (twice per year)	$3.81 per month	$4.47 per month
Monthly (12 times per year)	No change (12 times per year)	$22.89 per month	$26.79 per month

Consistent with the approach proposed in the 2023-2024 GRA, NS Power will conduct semi-annual meter readings for customers whose meters are currently read bi-monthly (i.e. Domestic and Small General classes). For customer classes that include a monthly demand charge (i.e. General, Large General, Small Industrial, Medium Industrial, Large Industrial, and the Municipal Tariff), meters will continue to be read monthly to determine the monthly demand for customers.

[27] M10431, Decision – para. 340.
[28] M10431, NS Power 2023-2024 GRA, Exhibit N-155, Schedule "A" Terms of Settlement, GRA Element "Misc. Charges (incl. AMI opt-out, […])," page 6 (PDF page 10). November 24, 2022.

NS Power's financial model for the opt-out charges is attached in **PR-02 Attachment 1** and changes to the AMI opt-out fee financial model since the last GRA are described in **Appendix 13B**. The Company has refreshed the jurisdictional scan conducted as part of its AMI Application (M08349), provided in **Appendix 13A,** and has included the 2024 Opt-out Costs Report as **Appendix 13C**.

In its Decision under M10431, the Board provided:

> Recognizing that current Regulations require monthly or bi-monthly meter readings, the Board will consider future amendments as may be appropriate.[29]

NS Power is proposing amendments, introducing three new terms and associated definitions, to Section 1.1 of its Regulations, provided as **PR-03 Attachment 1a and 2a.** These amendments relate to "Estimated Meter Read," "Opt-Out Fee," and "True Meter Read."

As customers who choose non-standard meter service will see a reduction in the number of physical meter reads (and increase in the number of estimated meter reads/bills) they receive, the Company seeks Board approval of amendments to Regulation 5.1 (Meter Reading) of the Regulations to reflect changes related to the introduction of AMI across the Province. The proposed amendments to Regulation 5.1 are attached in **PR-03 Attachment 1b and 2b**.

The opt-out charge is set out in NS Power's proposed amendment to Regulation 7.1 (Schedule of Charges), provided as **PR-03 Attachment 1c and 2c**.

13.8 Pole Attachment Fees

NS Power charges telecommunications carriers a rate to attach their equipment to poles owned by NS Power (pole attachment fee). This issue was canvassed in the 2023-2024 GRA, and the telecommunications carriers (Eastlink, Rogers and Xplore) ultimately entered into a settlement agreement setting out the rate increase. The settlement was based on a charge of $22 per pole per year, with a 2 percent increase effective January 1 in each of 2023 and 2024.

[29] M10431, NS Power GRA, NSEB Decision, 300864, page 169, para. 439, February 3, 2023.

NS Power is proposing that the 2 percent annual increase continues, resulting in a 4 percent increase in 2026 and a 2 percent increase in 2027. The updated pole attachment rates are set out in **Figure 13-6** below. The updated Pole Attachment fees are included in **PR-03 Attachment 1c and 2c.** NS Power can confirm that Eastlink, Rogers, and Xplore are in agreement with these increases.

Figure 13-4 – Pole Attachment Fees 2026 and 2027

2026 Increase	2026 Fee	2027 Increase	2027 Fee
4 percent	$23.81	2 percent	$24.29

13.9 Open Access Transmission Tariff

NS Power has reviewed and updated the prices for services offered under the Open Access Transmission Tariff (OATT). Most of the methodology for the OATT rates remains unchanged from the 2023-2024 GRA. Please refer to **SR-01 Attachment 1e** and **SR-01 Attachments 11-14**.

Further information on the OATT and the 2023-2024 GRA-related OATT directives can also be found in **SR-01 Attachment 1e.**

13.10 Distribution Tariff

With respect to service in the Renewable to Retail Market, NS Power has reviewed and updated charges for the distribution and retail services offered under the Distribution Tariff (DT) and Distribution Tariff Rates (DTR). The methodology for the DT remains unchanged from the 2023-2024 GRA with the exception of the Large Industrial Rate (LIR) which is proposed to include separate charges for distribution- and transmission-connected customers.

The DTR approved for use in the 2023-2024 GRA featured one distribution charge applicable to distribution connected LIR customers consistent with Distribution Tariff Section 3 - Scope of the Distribution Tariff which defines services under this tariff as applicable to all RTR Customers connected to the Distribution System.

Recent engagement undertaken in preparation for implementation of RTR service in 2026 revealed a gap in the current DT regarding recovery of retail service costs from potential transmission-connected LIR customers migrating to the Licensed Retail Supplier (LRS). Even though the transmission-connected RTR customers would not utilize the distribution system, they would continue to rely on retail services such as metering, meter data services, call centre etc. provided to them currently under the bundled service tariff. Under the existing RTR design there is no provision for recovery of these costs. Absent the proposed amendment to the DTR, these costs would be recovered from other customers. To align the DT with the proposed changes to the DTR, the Company is proposing changes to Section 3 - Scope of the Distribution Tariff. Please refer to **PR-01 Attachments 1u and 2u**.

In addition to the above amendments, NS Power has included the DSM and Storm Cost Recovery Rider (SCRR) provisions in the DTR consistent with the design of bundled service tariffs.

13.11 FAM Tariff and POA Updates to Account for Load Migrations

As part of its Decision and Order in the 2024 FAM AA/BA proceeding, the NSEB directed NS Power to amend the FAM Tariff to account for customers moving out of the FAM class and back into the FAM class. Previously, the FAM Tariff was only amended to account for customers moving out of the FAM classes.

NS Power currently has a process for Municipal Electric Utilities (MEU) and other large customer load migrations. For RTR Market-related migrations, the Company continues to work with the Licensed Retail Supplier (LRS) to determine a viable solution that leverages established regulatory processes, minimizes FAM class impacts, and minimizes the administrative burden to the Company. Based on existing processes for MEU load migrations and the current state of the RTR market, the Company has proposed amendments to account for customers migrating load between FAM and non-FAM classes, without explicit attempt to incorporate LRS-related load migrations.

NS Power has amended Special Condition 3 of the FAM Tariff, included in **PR-01 Attachments 1s and 2s**, and Section 3.1 of the Plan of Administration as set out in **Appendix 6B.**

For load migrations to non-FAM classes, balances accrued while the customer load was fully or partially served on an above-the-line Tariff would be settled. Load migrations from non-FAM classes would be similarly treated; balances would be settled outside of the Fuel Adjustment Rider until it is appropriate to return the customer to the Rider (e.g. the Rider includes balances accumulated for the same full period in which the customer was taking FAM class service). Due to the size and nature of MEU and other large load customers, both fuel cost imbalance calculations, for load migrations from a FAM class, and tracking load migrations back to a FAM class, for the purposes of assessing the applicability of the in-effect Fuel Adjustment Rider, are sustainable. Migrations of small volume customers within the RTR Market require further consideration (i.e. volume, frequency of migrations, class, and system capabilities) to determine the most sustainable and least administratively burdensome approach. Future changes to the FAM Tariff, and to the POA, may be required to accommodate treatment of small volume customer load migrations resulting from the RTR Market.

14 PROPOSED RATES

14.1 Rate-setting Process Overview

Once the revenue requirement has been established, it is apportioned among rate classes based on their usage through COSS. The COSS results provided foundation for determination of class revenue responsibility through application of the Board approved revenue to cost ratio process. The process consists of applying first an across-the-board increase to each class revenues and then making adjustments to those classes whose ratios fall outside of the 95 to 105 band. The resulting changes in revenue responsibilities by rate classes provide foundation for revisions to customer rates.

14.2 Proposed Rates

In keeping with the proposed Cost of Service Study, rate design for this Application encompasses customer, demand, and energy charges as well as specific items outlined in Section 13.

The revenue responsibilities attributed to each rate class were determined as set out in **SR-01 Attachments 2, 3 and 7**, form an input into the calculation of the proposed rate components shown in **SR-01 Attachment 8.**

The Proof of Revenue section included in **OR-01 Attachment 1** presents the detailed calculation for each rate component. **Figure 14-1** provides the percentage increases by customer class for both fuel and non-fuel components.

Figure 14-1 – Percentage Increases by Customer Class (Fuel and Non-Fuel)

Customer Class	2026	2027
Domestic Service		
Fuel	1.2	(0.4)
Non-Fuel	2.6	4.4
Total	3.8	4.1
Small General		
Fuel	2.7	(0.8)
Non-Fuel	1.0	4.8
Total	3.7	4.0

Customer Class	2026	2027
General		
Fuel	3.5	(3.2)
Non-Fuel	(3.6)	3.7
Total	(0.1)	0.5
Large General		
Fuel	3.8	(5.7)
Non-Fuel	(8.2)	2.5
Total	(4.4)	(3.2)
Small Industrial		
Fuel	4.7	(3.3)
Non-Fuel	(5.2)	3.5
Total	(0.4)	0.3
Medium Industrial		
Fuel	3.8	(6.7)
Non-Fuel	(10.3)	1.9
Total	(6.4)	(4.8)
Large Industrial Firm Transmission Service		
Fuel	4.1	(6.6)
Non-Fuel	(10.2)	2.4
Total	(6.2)	(4.3)
Large Industrial Firm Distribution Service		
Fuel	3.9	(6.3)
Non-Fuel	(9.3)	2.6
Total	(5.4)	(3.7)
Large Industrial Interruptible Transmission Service		
Fuel	4.9	(8.0)
Non-Fuel	(11.9)	2.6
Total	(7.0)	(5.4)
Large Industrial Interruptible Distribution Service		
Fuel	4.5	(7.5)
Non-Fuel	(11.8)	3.3
Total	(7.3)	(4.2)
Large Industrial Total		
Fuel	4.6	(7.6)
Non-Fuel	(11.5)	2.8

Customer Class	2026	2027
Total	(6.9)	(4.7)
Municipal Class		
Fuel	9.6	(0.4)
Non-Fuel	(7.9)	3.4
Total	1.7	3.0
Unmetered Class		
Fuel	(0.7)	2.8
Non-Fuel	8.6	4.6
Total	7.9	7.3
Total FAM Classes		
Fuel	2.3	(1.7)
Non-Fuel	(0.5)	4.1
Total	1.8	2.4

Figure 14-2 and **Figure 14-3** show the rates for the tariffs of NS Power's customers for 2026 and 2027.

Figure 14-2 – Proposed 2026 Rates

Proposed Rate Changes	Units	Current 2025	Proposed for 2026	Percentage Change
Domestic Service Tariff				
Customer Charge	\$/mo.	19.17	20.24	5.6
Energy Charge	¢/kWh	17.928	18.610	3.8
DSM Rider	¢/kWh	0.633	0.633	0.0
Small General Tariff				
Customer Charge	\$/mo.	21.28	22.16	4.1
Energy Charge (Block 1, first 200 kWh)	¢/kWh	18.474	19.209	4.0
Energy Charge (Block 2)	¢/kWh	16.748	17.380	3.8
DSM Rider	¢/kWh	0.753	0.753	0.0
General Tariff				
Demand Charge	\$/kW	10.554	9.838	-6.8
Energy Charge (Block 1, first 200 kWh)	¢/kWh	14.977	15.053	0.5
Energy Charge (Block 2)	¢/kWh	11.680	11.980	2.6

Proposed Rate Changes	Units	Current 2025	Proposed for 2026	Percentage Change
DSM Rider	¢/kWh	0.646	0.646	0.0
Large General Tariff				
Demand Charge	$/kVA	13.845	11.201	-19.1
Energy Charge	¢/kWh	11.507	11.397	-1.0
DSM Rider		0.790	0.790	0.0
Small Industrial Tariff				
Demand Charge	$/kVA	8.332	7.506	-9.9
Energy Charge (Block 1, first 200 kWh)	¢/kWh	13.873	14.010	1.0
Energy Charge (Block 2)	¢/kWh	11.299	11.692	3.5
DSM Rider	¢/kWh	0.753	0.753	0.0
Medium Industrial Tariff				
Demand Charge	$/kW	13.796	10.728	-22.2
Energy Charge	¢/kWh	11.044	10.952	-0.8
DSM Rider	¢/kWh	0.314	0.314	0.0
Large Industrial Tariff				
Demand Charge	$/kVA	12.601	9.280	-26.4
Interruptible Credit	$/kVA	-7.486	-7.638	2.0
Distribution Cost Adder	$/kVA	1.632	2.332	42.9
Energy Charge (Firm-Transmission)	¢/kWh	10.799	10.614	-1.4
Energy Charge (Firm - Distribution)	¢/kWh	10.836	10.614	-1.7
Energy Charge (Interruptible - Transmission)	¢/kWh	10.776	10.630	-1.0
Energy Charge (Interruptible - Distribution)	¢/kWh	10.813	10.630	-1.4
DSM Rider	¢/kWh	0.431	0.431	0.0
Municipal Tariff				
Demand Charge	$/kVA	13.428	11.330	-15.6
Energy Charge	¢/kWh	10.658	11.741	10.2
DSM Rider	¢/kWh	0.627	0.627	0.0

1 **Figure 14-3 – Proposed 2027 Rates**

Proposed Rate Changes	Units	Proposed 2026	Proposed for 2027	Percentage Change
Domestic Service Tariff				
Customer Charge	$/mo.	20.24	21.38	5.6
Energy Charge	¢/kWh	18.610	19.372	4.1
DSM Rider	¢/kWh	0.633	0.633	0.0
Small General Tariff				
Customer Charge	$/mo.	22.16	23.07	4.1
Energy Charge (Block 1, first 200 kWh)	¢/kWh	19.209	20.107	4.7
Energy Charge (Block 2)	¢/kWh	17.380	18.081	4.0
DSM Rider	¢/kWh	0.753	0.753	0.0
General Tariff				
Demand Charge	$/kW	9.838	10.709	8.9
Energy Charge (Block 1, first 200 kWh)	¢/kWh	15.053	15.029	-0.2
Energy Charge (Block 2)	¢/kWh	11.980	11.683	-2.5
DSM Rider	¢/kWh	0.646	0.646	0.0
Large General Tariff				
Demand Charge	$/kVA	11.201	11.201	0.0
Energy Charge	¢/kWh	11.397	10.760	-5.6
DSM Rider		0.790	0.790	0.0
Small Industrial Tariff				
Demand Charge	$/kVA	7.506	8.143	8.5
Energy Charge (Block 1, first 200 kWh)	¢/kWh	14.010	13.894	-0.8
Energy Charge (Block 2)	¢/kWh	11.692	11.379	-2.7
DSM Rider	¢/kWh	0.753	0.753	0.0
Medium Industrial Tariff				
Demand Charge	$/kW	10.728	11.277	5.1
Energy Charge	¢/kWh	10.952	10.095	-7.8
DSM Rider	¢/kWh	0.314	0.314	0.0
Large Industrial Tariff				
Demand Charge	$/kVA	9.280	10.000	7.8
Interruptible Credit	$/kVA	-7.638	-7.667	0.4

Proposed Rate Changes	Units	Proposed 2026	Proposed for 2027	Percentage Change
Distribution Cost Adder	$/kVA	2.332	2.527	8.3
Energy Charge (Firm-Transmission)	¢/kWh	10.614	9.925	-6.5
Energy Charge (Firm - Distribution)	¢/kWh	10.614	9.925	-6.5
Energy Charge (Interruptible - Transmission)	¢/kWh	10.630	9.882	-7.0
Energy Charge (Interruptible - Distribution)	¢/kWh	10.630	9.882	-7.0
DSM Rider	¢/kWh	0.431	0.431	0.0
Municipal Tariff				
Demand Charge	$/kVA	11.330	12.270	8.3
Energy Charge	¢/kWh	11.741	11.892	1.3
DSM Rider	¢/kWh	0.627	0.627	0.0

NS Power proposes to smooth the overall increases (combined BCF and non-fuel rates) for each rate class during the 2026-2027 GRA period through changes to the BCF.

The percentage annual fuel increases in individual classes are proposed to be set based on the assumption that by the end of the 2026-2027 GRA period all rate classes will have paid their total fuel costs for the test period.

15 REGULATIONS

15.1 Regulations 1.1, 5.1, 7.1 and 7.3

NS Power's updated request for an AMI opt-out fee is presented above in section 13.7. Such a change will require an update to Regulation 1.1 as provided in **PR-03 Attachments 1a and 2a,** Regulation 5.1 as provided in **PR-03 Attachment 1b and 2b,** Regulation 7.1 as provided in **PR-03 Attachment 1c and 2c**, and Regulation 7.3 as provided in **PR-03 Attachment 1d and 2d**.

The changes to Regulation 1.1 update the definitions to include estimated meter read, opt-out fee, and true or actual meter read. Changes to Regulation 5.1 update meter reading and the ability to charge an AMI opt-out fee. Changes to Regulation 7.1 update the Schedule of Charges to include the AMI opt-out fee, and the updated pole attachment fees. Changes to Regulation 7.3 update the rates charged for Recovery of Installation and Operational Charges.

16 RELIEF REQUESTED

NS Power seeks an order approving the following:

1. The 2026 and 2027 revenue requirements as described in **Section 11** to enable NS Power to recover the prudent and reasonable costs of providing service to customers and to meet its financial obligations.

2. As described in **Section 5**, the BCF amounts attributable to FAM customers be set at $927.3 million for 2026 and $850.9 million for 2027, which represent the smoothed amounts.

3. The amendments to the FAM Plan of Administration as described in **Section 6** and **Appendix 6A** and set out in **Appendix 6B**.

4. As set out in **Section 5**, the change to the language in the introduction to Appendix Q (the Hedging Plan) of the Fuel Manual so that it is generic and not tied to specific years or rate periods. This change is administrative and does not affect the substantive content of NS Power's Hedging Plan or specific hedging targets.

5. As set out in **Section 8**, inclusion of GRA-related costs in the deferral and regulatory asset previously approved by the Board in its 2023-2024 GRA Decision for COSS, Line Loss Study, and Climate Change Adaptation Plan costs.

6. As described in **Section 9.2**, if securitization of the unrecovered net book value of generation assets within the scope of the DDA is delayed such that it cannot be completed in whole or in part by January 1, 2026, NS Power is requesting that depreciation expense and financing costs of these assets be deferred at WACC on an interim basis.

7. As set out in **Section 11.2**, approval of the EIFEL Deferral.

8. As set out in **Section 12.4**, approval of the PHP Deferral.

9. As set out in **Appendix 12A**, the updated Cost-of-Service Study.

10. All rates, charges and regulations requested in this Application, which, in addition to the rates set out in **Section 14 Figure 14-1, Figure 14-2, and Figure 14-3** and **PR-01 and PR-03.**

11. Continuation of the Storm Cost Recovery Rider pilot in 2026 and 2027, but on a symmetrical basis as described in **Section 13.6**.

12. Nova Scotia Power's Capital Structure and Cost of Capital as described in **Section 10**.

13. Such other relief as may be required to bring effect to that which is requested herein.

The relief requested by NS Power is subject to such further information as may be provided by the Company to the Board throughout the regulatory process, including its Compliance Filing.