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All the time.

MARITIME ELECTRIC
A FORTIS COMPANY

December 11, 2025

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The Island Regulatory and Appeals Commission

Island Regulatory & Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Commissioners:

Application for an Order to Approve an ECAM Rate Adjustment

Please find enclosed five (5) copies of Maritime Electric's Application for an Order approving an ECAM Rate Adjustment of $0.01949 per kWh beginning on March 1, 2026 in accordance with Section N-0 of the Company's Rates and General Rules and Regulations.

An electronic copy will follow.

If you require further information, please do not hesitate to contact me at 902-629-3701.

Yours truly,

MARITIME ELECTRIC

Michelle Francis
Vice President, Finance &
Chief Financial Officer

MF53
Attachments

180 Kent Street • PO Box 1328 • Charlottetown, PE C1A 7N2
telephone 1-800-670-1012 • **fax** 902-629-3665 • **maritimeelectric.com**

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY
AND APPEALS COMMISSION

IN THE MATTER of Section 3(a), 10, 13(1) and 20 of the *Electric Power Act* (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order approving an Energy Cost Adjustment Mechanism rate adjustment to customers' bills for the period March 1, 2026 to February 28, 2027 and for certain approvals incidental to such an order.

APPLICATION
AND
EVIDENCE OF
MARITIME ELECTRIC COMPANY, LIMITED

December 11, 2025

TABLE OF CONTENTS

APPENDICES

1.0 APPLICATION

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

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Introduction

Maritime Electric Company, Limited ("Maritime Electric" or the "Company") is a public utility subject to the *Electric Power Act ("the Act")* engaged in the production, purchase, transmission, distribution and sale of electricity within Prince Edward Island.

Application

Maritime Electric hereby applies for an order of the Island Regulatory and Appeals Commission ("IRAC" or the "Commission") approving an Energy Cost Adjustment Mechanism rate adjustment to customers' bills for the period March 1, 2026 to February 28, 2027 and for certain approvals incidental to such an order.

Procedure

Filed herewith is the Affidavit of Jason C. Roberts, T. Michelle Francis, Angus S. Orford and Enrique A. Riveroll which contains the evidence on which Maritime Electric relies in this Application.

Dated at Charlottetown, Province of Prince Edward Island, this 11th day of December, 2025.

D. Spencer Campbell, K.C.

STEWART MCKELVEY
65 Grafton Street, PO Box 2140
Charlottetown PE C1A 8B9
Telephone: 902-629-4549
Solicitors for Maritime Electric Company, Limited

2.0 AFFIDAVIT

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of Section 3(a), 10, 13(1) and 20 of the *Electric Power Act* (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order approving an Energy Cost Adjustment Mechanism rate adjustment to customers' bills for the period March 1, 2026 to February 28, 2027 and for certain approvals incidental to such an order.

AFFIDAVIT

We, Jason Christopher Roberts of Suffolk, T. Michelle Francis of Emyvale, Angus Sumner Orford of Charlottetown and Enrique Alfonso Riveroll of New Dominion, in Queens County, Province of Prince Edward Island, MAKE OATH AND SAY AS FOLLOWS:

We are the President and Chief Executive Officer, Vice President, Finance and Chief Financial Officer, Vice President, Corporate Planning and Energy Supply and Vice President, Customer Service for Maritime Electric Company, Limited ("Maritime Electric" or the "Company"), respectively, and as such have personal knowledge of the matters deposed to herein, except where noted, in which case we rely upon the information of others and in which case we verily believe such information to be true.

Maritime Electric is a public utility subject to the provisions of the *Electric Power Act* engaged in the production, purchase, transmission, distribution and sale of electricity within Prince Edward Island.

We prepared or supervised the preparation of the evidence and to the best of our knowledge and belief the evidence is true in substance and in fact.

SWORN TO SEVERALLY at
Charlottetown, Prince Edward Island,
the 11th day of December, 2025.

____
Jason C. Roberts

____
T. Michelle Francis

____
Angus S. Orford

____
Enrique A. Riveroll

____
A Commissioner for taking affidavits
in the Supreme Court of Prince Edward Island.

3.0 EXECUTIVE SUMMARY

3.1 Background

The Energy Cost Adjustment Mechanism ("ECAM"), as approved by IRAC, is a mechanism that ensures the timely collection of prudently incurred energy supply costs from customers and allows for the deferral of unplanned fluctuations in energy supply costs during a rate-setting period or designated period of time.

At the beginning of a rate-setting period, the basic energy charge included in customer rates reflects a forecast of annual energy supply costs based on the Base Rate Cost, as defined in the ECAM and approved by the Commission. As actual energy supply costs incurred by Maritime Electric differ from the Base Rate Cost, the difference is deferred in the ECAM account to be collected from or refunded to customers in a future period via an ECAM Rate Adjustment applied to customers' bills, as approved by the Commission. The ECAM balance is reported to the Commission as part of the Company's monthly financial statements submission.

In June 2020, the Company filed a comprehensive review of the ECAM energy supply accounts to the Commission. Order UE21-05 approved the continued operation of the ECAM and the proposed revisions to the accounts, which were implemented in the next General Rate Application ("GRA") effective May 1, 2023. However, the Commission rejected the proposal for automatic ECAM Rate Adjustment resets, citing concerns over reduced regulatory oversight and potential for increased rate fluctuations and decreased predictability for customers.

The Company, therefore, submits this Application requesting approval of an increase to the ECAM Rate Adjustment effective March 1, 2026, and to remain in effect until February 28, 2027, or until otherwise approved by the Commission.[1]

[1] In GRA Order UE23-04, the Commission approved ECAM rate adjustments of $0.00589 per kWh from May 1, 2023, to February 29, 2024, $0.00287 per kWh from March 1, 2024, to February 28, 2025, and $0.00145 per kWh from March 1, 2025, to February 28, 2026. Subsequently, in Order UE23-09, an additional ECAM rate adjustment of $0.0033 per kWh was approved, effective October 1, 2023. This resulted in a total ECAM collection rate of $0.00919 per kWh from October 1, 2023, $0.00617 per kWh from March 1, 2024, and $0.00475 per kWh from March 1, 2025, remaining in effect until February 28, 2026, or until further varied by the Commission.

3.2 2023, 2024 and 2025 ECAM Balances

As stated in the previous application to adjust the ECAM collection rate, Docket UE20605 filed on July 26, 2023, the actual ECAM balance on December 31, 2022 was $4.9 million higher than the balance forecast in the Company's GRA filed with the Commission on June 20, 2022.

As of December 31, 2023, the ECAM account recorded a balance of $11.7 million, which was $7.6 million higher than the forecasted balance in the Company's GRA. This trend continued into 2024, with the ECAM balance reaching $20.6 million by year-end, exceeding the GRA forecast by $18.5 million. By December 31, 2025, the ECAM balance is forecast to be $32.0 million, surpassing the GRA forecast by $31.9 million. A monthly ECAM schedule of actual energy costs deferred to ECAM and ECAM adjustment collections since December 31, 2022 is provided in Appendix A.[2]

The variances in the ECAM balances for these years were primarily driven by actual energy supply costs exceeding forecasted amounts. In 2023, additional energy costs amounted to $4.1 million, while in 2024 and 2025, these costs increased to $16.5 million and $19.0 million, respectively. These additional costs were largely due to higher than anticipated energy supply expenses related to replacement energy during outages at the Point Lepreau Nuclear Generating Station ("Point Lepreau"), as well as increased wind replacement costs and net metering costs.

During this period, actual customer collections through the ECAM were also higher than forecasted in the GRA. In 2023, collections exceeded forecasts by $1.4 million, followed by $5.7 million in 2024, and $5.6 million in 2025. The increase in collections were a result of higher-than-expected kWh sales as well as the additional ECAM Rate Adjustment approved in Order UE23-09, which was not included in the original GRA forecast.

In summary, the increase in the December 31, 2022 opening balance in ECAM of $4.9 million together with energy costs that were $39.6 million higher than forecast in the GRA for 2023, 2024 and 2025 less higher than expected ECAM customer collections of $12.7 million over the

[2] Appendix A includes actual energy costs deferred and ECAM adjustment collections for 2023 and 2024. For 2025, Appendix A includes actual energy costs deferred and ECAM adjustment collections up to September 30, 2025 and forecast costs deferred and ECAM adjustment collections for the remainder of the year.

same three-year period have resulted in a forecast balance in ECAM that is $31.9 million higher than forecast in the GRA as of December 31, 2025 and a net balance of $32.0 million that needs to be collected from customers as of December 31, 2025.[3]

3.3 Proposed ECAM Rate Adjustment Applied to Customers' Bills

Based on the approved formula set out in Section N-0 of the Company's Rates and General Rules and Regulations, the Company requests approval of an increase to the ECAM Rate Adjustment to be applied to customers' bills of $0.01949 per kWh effective March 1, 2026 to February 28, 2027 or until otherwise approved by the Commission, as discussed in Section 7.0 of this Application.

3.4 Customer Impact

A schedule of existing rates for all customer classes, which were effective March 1, 2025, and the proposed rates for March 1, 2026 including the proposed ECAM Rate Adjustment, is provided in Appendix C.

Benchmark Residential customers will experience an annual cost increase of approximately 7.3 to 7.4 per cent, while General Service customers will experience an increase of approximately 6.8 per cent. These impacts reflect the proposed ECAM Rate Adjustment, as shown in Tables 24, 25 and 26 of this Application.[4] Industrial customers have widely varying consumption and demand profiles, which will result in varying impacts to their annual costs; however, a reasonable estimate would be an increase of 9.0 per cent for Small Industrial Customers and 13.0 to 14.0 per cent for Large Industrial customers. A comparison, by customer class, of existing rates to the proposed rates including the ECAM Rate Adjustment is provided in Section 8.0 of this Application.

[3] The forecast balance of ECAM on December 31, 2025 in the GRA of $112,468 plus excess balance in ECAM as of December 31, 2022 of $4,864,231 plus additional energy costs deferred from 2023 through 2025 of $39,667,889, less higher than forecast collections of $12,663,544 results in an ECAM balance to be collected of $31,981,044 as of December 31, 2025.

[4] A benchmark Residential customer is a customer that consumes 1,000 kilowatt hours of energy per month. A benchmark General Service customer is a customer that consumes 10,000 kilowatt hours of energy and uses 50 kilowatts of demand per month.

4.0 INTRODUCTION

4.1 Corporate Profile

Maritime Electric owns and operates a fully integrated power system providing for the purchase, generation, transmission, distribution and sale of electricity throughout Prince Edward Island ("PEI"). The Company's head office is located in Charlottetown with generating facilities in Charlottetown and Borden-Carleton.

Maritime Electric is the primary provider of electricity on PEI, delivering approximately 90 per cent of the energy supplied on PEI. To meet customers' energy demand and supply requirements, the Company has contractual entitlement to capacity and energy from New Brunswick ("NB") Point Lepreau and an agreement for the purchase of capacity and system energy from NB Power delivered via four submarine cables owned by the Province of PEI.[5] Through various contracts with the PEI Energy Corporation ("PEIEC"), the Company purchases the capacity and energy from 129.5 megawatts ("MW") of wind and solar generation. In the event that generation fails to provide all the energy expected in these contracts, the shortfall is obtained through additional energy purchases from NB Power or by operating the Company's on-Island backup generation.

Maritime Electric is a public utility subject to the provisions of the *Electric Power Act*. As a public utility, the Company is subject to regulatory oversight and approvals of the Commission, whose jurisdiction to regulate public utilities is found in the *Electric Power Act* and the *Island Regulatory and Appeals Commission Act*.

4.2 Purpose

The purpose of this Application is to seek approval to change Maritime Electric's ECAM Rate Adjustment applied to customers' bills to collect the accumulated ECAM balance as of December 31, 2025 of $32.0 million. The $31.9 million increase in the ECAM balance over the forecast balance in the GRA is primarily attributable to:

[5] The Energy Purchase Agreement is between Maritime Electric and New Brunswick Energy Marketing.

- An increase in the balance of ECAM on December 31, 2022 over the forecast GRA balance of $4.9 million as previously filed with the Commission on July 26, 2023 in an Application to approve an increase in the ECAM Rate Adjustment to be applied to customer bills [Docket UE20605];
- An increase in actual costs of purchased and produced electricity exceeding the forecasted amounts for the years 2023, 2024 and 2025 in the Company's GRA filed with the Commission and approved in Order UE23-04 by $39.6 million; and
- Offset by additional collections from customers over the same period of $12.7 million compared to the GRA forecast.

4.3 Overview of ECAM

Maritime Electric has had a mechanism to provide for changes in energy-related costs since the 1970's.[6] The mechanism has undergone several modifications; however, the fundamental objectives have remained the same.

First, the ECAM provides a mechanism to ensure the timely collection or rebate of prudently incurred energy-related costs from customers. This timely collection or rebate addresses intergenerational equity as customers pay the related costs of the service they receive within a reasonable period, so as not to unnecessarily defer costs or benefits to future customers beyond the subsequent rate-setting period.

Secondly, by deferring unplanned fluctuations in energy-related costs during a rate-setting period, the ECAM offers a measure of customer rate predictability. The deferral of uncontrollable changes in energy-related costs enables the Company to develop rate proposals that appropriately manage the customer impact of collecting current period costs.

Together, these have been the fundamental objectives of the ECAM, which the Company and IRAC have followed in establishing customer rates and recovering or rebating uncontrollable fluctuations in energy-related costs. These types of regulatory mechanisms are commonly used in the electricity industry.

[6] During the price cap regulation period under the Maritime Electric Regulation Act period of 1994 to 2000 there was no mechanism in place.

The energy supply costs incurred by Maritime Electric on behalf of its customers are passed through to customers via the ECAM by two means.

First, customers pay the majority of the energy supply costs at the time the energy is consumed through the basic energy charge that forms part of customers' rates.[7] The energy supply costs included in the basic energy charge is determined by the Base Rate Cost, as defined in the ECAM, which is set to recover the forecast annual energy supply costs for the year.

Second, customers pay any deferred energy supply costs that result from variances in actual energy supply costs from forecast in a prior period. The customers' ECAM Rate Adjustment is calculated by the Company, and approved by the Commission, to appropriately collect the deferred energy supply costs over a reasonable period, thereby providing rate stability and predictability.

The operation of the ECAM serves an important function to customers, the Company and the Commission for the following reasons:

- it provides stable and predictable rates for customers over a rate-setting period;
- it provides financial stability for Maritime Electric, and timely collection of incurred energy-related costs, supporting the Company's financial health; and
- it provides regulatory efficiency by avoiding frequent rate change applications to address energy supply cost fluctuations.

In Order UE21-05 issued July 28, 2021, the Commission approved the continued operation of the ECAM following a comprehensive review of the ECAM, which had been filed with the Commission on June 1, 2020.

In Order UE23-04 issued April 24, 2023, the Commission approved an ECAM collection rate per kilowatt hour ("kWh") of $0.00589 for the period May 1, 2023 to February 29, 2024 and

[7] For the year ended December 31, 2023, 94.6 per cent of gross energy costs were recovered through basic rates while 89.4 per cent of gross energy costs were recovered through basic rates for the year ended December 31, 2024 and 89.9 per cent of gross energy costs are forecast to be recovered through basic rates for the year ended December 31, 2025.

$0.00287 for the period March 1, 2024 to February 28, 2025 and $0.00145 for the period March 1, 2025 to February 28, 2026 based on the Company's GRA updated in the negotiated settlement filed in February 2023.

Pursuant to the UE23-04 directive, the Company was obligated to address the difference in the forecast ECAM balance as of December 31, 2022 in the GRA and the actual ECAM balance on December 31, 2022 by submitting an additional ECAM Rate Adjustment application to the Commission by July 31, 2023, for a rate adjustment effective October 1, 2023.

On July 26, 2023, the Company filed the required ECAM Rate Adjustment application with the Commission. In Order UE23-09, the Commission approved the requested ECAM Rate Adjustment of $0.0033 per kWh, effective October 1, 2023 and ordered the adjustment remain in effect until the end of the GRA period or February 28, 2026. As a result of both Orders UE23-04 and UE23-09, the approved total ECAM collection rates are $0.00919 per kWh effective October 1, 2023, $0.00617 per kWh effective March 1, 2024 and $0.00475 per kWh effective March 1, 2025.

The ECAM Rate Adjustment proposed in this Application is $0.01949 per kWh effective from March 1, 2026 to February 28, 2027 or until otherwise determined by the Commission.

5.0 ENERGY SUPPLY COSTS – ACTUAL VERSUS GRA FORECAST

5.1 Introduction

Table 1 below summarizes the forecast Base Rate Costs used to set customer rates for the period January 1, 2023 through February 28, 2026, along with the corresponding regulatory approval orders.

TABLE 1
Forecast Base Rate Costs

Effective Dates	Forecast Base Rate Cost (per kWh)	Approved In
January 1, 2023 – April 30, 2023	$0.09244	Order UE21-03
May 1, 2023 – February 29, 2024	$0.09050	Order UE23-04
March 1, 2024 – February 28, 2025	$0.09440	Order UE23-04
March 1, 2025 – February 28, 2026	$0.09612	Order UE23-04

Actual energy costs incurred by the Company in 2023, 2024 and 2025 were higher than forecast, and the resulting increase in purchased and produced electricity costs was appropriately deferred in the ECAM account.

The ECAM balance is comprised of approximately $4.1 million, $16.5 million and $19.0 million of additional energy costs incurred during 2023, 2024 and 2025, respectively, above the amounts forecast in the GRA as summarized in Table 2.

TABLE 2 Energy Costs Deferred to ECAM January 1 to December 31				
		2023	**2024**	**2025[8]**
Total Actual Energy Costs Applicable to ECAM	A	$ 153,351,328	$ 172,463,791	$ 181,969,150
Total Actual Net Purchased and Produced Energy (kWh)	B	1,586,443,607	1,634,952,719	1,696,369,386
ECAM Base Rate per kWh[9]	C	$ 0.09122	$ 0.09360	$ 0.09576
Total Base Energy Costs	D = B * C	144,710,043	153,030,837	162,437,444
Energy Costs Deferred to ECAM	**E = A - D**	**$ 8,641,285**	**$ 19,432,954**	**$ 19,531,706**
GRA Forecast Energy Costs Deferred to ECAM[10]	F	4,496,080	2,923,640	518,338
Additional Energy Costs Deferred to ECAM over GRA Forecast	**G = E - F**	**$ 4,145,205**	**$ 16,509,314**	**$ 19,013,368**

In addition, customer ECAM collections were $1.4 million, $5.7 million and $5.6 million higher than forecast for 2023, 2024, and 2025, respectively, as summarized in Table 3. The higher collections are due in part to higher-than-forecast sales as well as the approval of an additional amount of $0.0033 per kWh effective October 1, 2023, for the remaining duration of the GRA as per Order UE23-09. Further details regarding ECAM collections are provided in Section 6.0.

TABLE 3 ECAM Collections from Customers January 1 to December 31				
		2023	**2024**	**2025[11]**
Actual ECAM Collections from Customers	A	$ (8,610,353)	$ (10,568,268)	$ (8,101,578)
GRA Forecast ECAM Collections from Customers[12]	B	(7,218,463)	(4,912,674)	(2,485,518)
Excess in Actual ECAM Collections compared to GRA Forecast	**C = A - B**	**$ (1,391,890)**	**$ (5,655,594)**	**$ (5,616,060)**

8 Reflects actual values for January to September and forecast values for October to December, given that actual data for these months were not finalized at the time this application was prepared.

9 The ECAM Base Rate per kWh is the weighted average of the applicable monthly approved rates for the year. While the rate is displayed to five decimal places, the underlying calculation uses the full weighted average carried out to sixteen decimal places.

10 As shown in Table 4 (ECAM Deferral) on page 3 of the letter dated April 4, 2023, titled Settlement Related to the 2023 General Rate Application, which was subsequently approved by the Commission in Order UE23-04.

11 Reflects actual values for January to September and forecast values for October to December, given that actual data for these months were not finalized at the time this application was prepared.

12 GRA Appendix H, adjusted to reflect a two-month delay in the implementation of Order UE21-05, as noted in the letter dated April 4, 2023, titled Settlement Related to the 2023 General Rate Application, which was subsequently approved by the Commission in Order UE23-04.

Table 4 shows the ECAM balance as of December 31, 2023, 2024, and 2025, and the fact that these balances were $7.6 million, $18.5 million, and $31.9 million higher than forecast in the GRA.

TABLE 4
ECAM Balance
January 1 to December 31

		2022		2023	2024	2025[13]
Actual ECAM Balance	A	$ 11,655,299	D = A + Table 2 E + Table 3 B[14]	$ 11,686,231	$ 20,550,917	$ 31,981,044
GRA Forecast ECAM Balance	B	6,791,068	E = B + Table 2 F + Table 3 A	4,068,685	2,079,651	112,471
ECAM Balance above GRA Forecast	**C = B - A**	**$ 4,864,231**	**F = D - E**	**$ 7,617,546**	**$ 18,471,266**	**$ 31,868,573**

The variances are driven by increases in energy costs of $4.1 million, $16.5 million, and $19.0 million for 2023, 2024, and 2025, respectively (see Table 2) deferred to ECAM, combined with higher-than-forecast customer collections of $1.4 million, $5.7 million, and $5.6 million for the same years (see Table 3). A monthly ECAM schedule detailing actual energy costs deferred and collections from customers is provided in Appendix A.[15]

As shown in Table 2, the Company's actual energy costs for 2023, 2024, and 2025 exceeded the forecasts in the GRA. Table 5 below provides a breakdown of the energy cost components that contributed to the additional costs deferred to/(from) ECAM compared to the GRA forecast, with further detail and explanation of each component provided in Sections 5.2 through 5.12.

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13 Reflects actual values for January to September and forecast values for October to December, given that actual data for these months were not finalized at the time this application was prepared.

14 The value in this row is calculated based on the previous year's ending ECAM balance. For example, for 2023, "A" equals the actual ECAM ending balance for 2022 ($11,655,299) plus Table 2, Row D (Energy Costs Deferred to ECAM) for 2023 and Table 3, Row B (Actual ECAM Collections from Customers) for 2023, to determine the actual ECAM balance for 2023. The same methodology is applied for 2024, 2025, and the GRA Forecast ECAM balance calculations.

15 The monthly ECAM schedule is also submitted to the Commission on a monthly basis as part of the Company's monthly reporting package.

TABLE 5 Additional Energy Costs Deferred to/(from) ECAM over GRA Forecast January 1 to December 31				
		Increase (Decrease) over GRA Forecast		
		2023	2024	2025[16]
Point Lepreau Replacement Energy Costs	Sec 5.2 -Table 6	$ 4,771,262	$ 12,942,031	$ 11,918,621
Point Lepreau Operating and Maintenance Costs	Sec 5.2 -Table 7	1,739	1,034,701	3,005,015
Wind Energy Costs	Sec 5.3 -Table 8	(556,885)	1,687,736	5,291,778
Net Metering Costs	Sec 5.4 -Table 9	966,622	1,521,485	2,679,103
Energy Purchase Agreement ("EPA") Ratchet Costs	Sec 5.5 -Table 10	610,201	1,860,924	(313,834)
Capacity Costs	Sec 5.6 -Table 11	-	450,000	679,965
Non-spinning Reserve Costs	Sec 5.7 -Table 12	460,552	-	-
Imbalance Costs	Sec 5.8 -Table 13	(334,863)	(3,161)	(768,266)
Energy Sales to Third Parties	Sec 5.9 -Table 14	(189,222)	(64,394)	(1,168,370)
Interconnection Costs	Sec 5.10 -Table 15	(604,451)	(487,419)	(395,130)
Energy Generation	Sec 5.11 -Table 16	388,802	(336,935)	1,331,602
ECAM Adjustments Related to Variances in Energy Sales	Sec 5.12 -Table 18	(1,368,552)	(2,095,654)	(3,247,116)
TOTAL		**$ 4,145,205**	**$ 16,509,314**	**$ 19,013,368**

5.2 Point Lepreau Costs

Point Lepreau costs are in accordance with the Point Lepreau Participation Agreement and the GRA forecast costs reflect inputs from NB Power. NB Power provides a detailed forecast of Maritime Electric's share of the facility's operating and maintenance costs reflecting planned outages for required maintenance.

As discussed in Section 5.0 of this Application, energy supply costs incurred in 2023, 2024 and 2025 were higher than those originally forecast in the GRA and the Base Rate Cost that was approved for the same years. One of the primary drivers of the increased energy supply costs is the longer actual outage durations at Point Lepreau in those years compared to the planned outage durations reflected in the GRA forecast. These outage periods affect the Company's

[16] Reflects actual values for January to September and forecast values for October to December as actual data for these months were not finalized at the time this application was prepared.

energy supply costs in two ways: (1) the Company must procure replacement energy to meet customer demand, often at a premium; and (2) the Company continues to incur its share of Point Lepreau's operating, maintenance and administration, and capital related charges ("OM&A") expenses even when the facility is not producing energy.[17] The latter can be higher than forecast depending on the cause of the outage and whether the outage is capital or maintenance related.

Table 6 is a comparison of the actual outage days to the forecast outages in the GRA, and the corresponding replacement energy costs compared to the GRA forecast. The increase in actual replacement energy costs over the GRA forecast was appropriately deferred to ECAM.

TABLE 6
Point Lepreau Replacement Energy Costs

Year		GRA Forecast[18]	Actual	Increase over GRA
2023	Cost of Replacement Energy	$ -	$ 4,771,262	**$ 4,771,262**
	Outage Days[19]	-	65	65
2024	Cost of Replacement Energy	$ 2,587,380	$ 15,529,411	**$ 12,942,031**
	Outage Days[20]	50	254	205
2025[21]	Cost of Replacement Energy	$ -	$ 11,918,621	**$ 11,918,621**
	Outage Days[22]	-	158	158

[17] Point Lepreau replacement energy for planned outages that were included in the energy forecasts used to negotiate the Energy Purchase Agreement with NB Energy Marketing is supplied at EPA prices. Replacement energy needed for extended or unplanned outages is subject to market availability and may be subject to a premium.

[18] The Point Lepreau Replacement Energy GRA forecast is based on NB Power's annual forecasts, as approved by the NB Power Nuclear Board of Directors. Replacement energy purchases are budgeted only for the planned maintenance outage days identified for each operating year. No replacement energy purchases were included in the GRA for unplanned outages.

[19] Total outage duration in 2023 was 65 days, consisting of 18 days in January, 16 days in April, 25 days in May and 6 days in November. This compares to zero outages forecast in the GRA.

[20] Total outage duration in 2024 was 255 days, consisting of 178 days from April to September, 31 days in October and 46 days in November and December. This compares to 50 outage days forecast in the GRA.

[21] The values presented for 2025 include forecast amounts for October, November, and December as actual data for these months were not finalized at the time this application was prepared.

[22] Total outage duration in 2025 was 158 days, consisting of 8 days in March, and a 150-day outage that began on July 14, 2025 that is forecast to end on December 10, 2025. This compares to zero outage days forecast in the GRA.

Under the terms of the Point Lepreau Participation Agreement, the Company is required to pay its proportionate share of the ongoing annual OM&A costs of the facility whether or not is producing energy.[23]

OM&A costs include monthly financing and depreciation charges on the Company's participation allocation of the total investment in Point Lepreau, charges for the facility's operation and maintenance, a monthly contribution toward future decommissioning costs, the monthly loan guarantee fee associated with the facility's financing and the monthly charge for carrying common stock inventory.

Fuel costs represent the direct cost of fuel used in operating Point Lepreau. Fuel inventory costs reflect the monthly charges for storing generating fuel at the facility.

Table 7 is a summary of the Company's actual Point Lepreau OM&A costs compared to the GRA forecast, and the differences appropriately deferred to ECAM.

TABLE 7
Point Lepreau OM&A Costs

Year		GRA Forecast	Actual	Increase (Decrease) Over GRA
2023	OM&A Costs	$ 24,164,507	$ 24,469,289	$ 304,782
	Fuel and Fuel Inventory Costs	1,316,396	1,013,353	(303,043)
	TOTAL	$ 25,480,903	$ 25,482,642	**$ 1,739**
2024	OM&A Costs	$ 23,527,909	$ 25,321,462	$ 1,793,553
	Fuel and Fuel Inventory Costs	1,132,727	373,875	(758,852)
	TOTAL	$ 24,660,636	$ 25,695,337	**$ 1,034,701**
2025[24]	OM&A Costs	$ 24,295,872	$ 27,659,790	$ 3,363,918
	Fuel and Fuel Inventory Costs	1,351,250	992,347	(358,903)
	TOTAL	$ 25,647,122	$ 28,652,137	**$ 3,005,015**

[23] The Point Lepreau Unit Participation Agreement is dated March 29th, 1994. As such, costs related to this agreement are recoverable under the Electric Power Act Section 47(4)(b).

[24] The values presented for 2025 include forecast amounts for October, November, and December as actual data for these months were not finalized at the time this application was prepared.

As shown in Table 7, the Company's actual OM&A costs exceeded the GRA forecast in 2023, 2024 and 2025. The 2023 and 2024 variances were driven by higher operation and maintenance costs. In 2025, OM&A is forecast to be $3.4 million above the GRA forecast driven by increased cost of capital and depreciation charges of $2.2 million and increased operation and maintenance costs of $1.2 million.

In contrast, fuel and fuel inventory costs were lower than forecast in all three years. These lower costs are consistent with the reduced operating days at the facility, resulting in less energy production and, therefore, less fuel consumed.

5.3 Wind Energy Costs

Wind energy purchase costs represent the cost of purchasing renewable wind energy from the PEIEC under Power Purchase Agreements. These costs reflect the price of energy actually generated by third-party wind farms located in the province.

The GRA assumed two new wind farms, 29.4 MW in eastern PEI and 40 MW in western PEI, would be in service in 2024 and 2025, respectively. These projects did not enter service as planned. In addition, significant maintenance issues at the Hermanville wind farm resulted in lower-than-expected wind energy production at this facility during the last three years. As a result of the delays and maintenance issues, the Company was required to purchase additional energy through the EPA, often at a premium, to replace the energy the new wind farms were expected to supply. As a result, the cost of wind replacement energy increased above forecast, as shown in Table 8.

Conversely, because of the maintenance issues in Hermanville and the two new wind farms were not operational, the Company incurred lower-than-forecast wind energy purchase costs, also shown in Table 8.

TABLE 8 Wind-Related Energy Costs				
Year		**GRA Forecast**	**Actual**	**Increase (Decrease) Over GRA**
2023	Wind Energy Purchase Costs	$ 24,760,131	$ 17,005,155	$ (7,754,976)
	Cost of Wind Replacement Energy	-	7,198,091	7,198,091
	TOTAL	$ 24,760,131	$ 24,203,246	**$ (556,885)**
2024	Wind Energy Purchase Costs	$ 34,881,989	$ 21,904,285	$ (12,997,704)
	Cost of Wind Replacement Energy	-	14,665,440	14,665,440
	TOTAL	$ 34,881,989	$ 36,569,725	**$ 1,687,736**
2025[25]	Wind Energy Purchase Costs	$ 47,866,428	$ 22,707,765	$ (25,158,663)
	Cost of Wind Replacement Energy	-	30,450,441	30,450,441
	TOTAL	$ 47,866,428	$ 53,158,206	**$ 5,291,778**

Overall, total wind energy costs transitioned from slightly below forecast in 2023 to above forecast in 2024 and 2025, driven primarily by higher-than-expected wind replacement energy costs that exceeded reductions in wind energy purchase costs. These variances reflect the Company's obligation to procure replacement energy for customers, often at a higher cost, when wind generation does not materialize as forecast.

5.4 Net Metering Costs

Net metering is a billing arrangement that allows customers who generate their own power, typically through solar panels or other renewable sources, and deliver any excess energy back to the Company's electrical system. Customers are credited for the excess energy they supply which offsets their electricity consumption from the grid during periods when their generation is insufficient to meet their electricity needs. All net metering installations are governed by the *Renewable Energy Act*.

[25] The values presented for 2025 include forecast amounts for October, November, and December 2025 as actual data for these months were not finalized at the time this application was prepared.

The variance between the GRA forecast and actual net metering costs for 2023, 2024, and 2025, summarized in Table 9, is primarily the result of (i) higher-than-forecast growth in customer owned solar generation and (ii) the Company's obligation to compensate net metering customers for their excess energy supplied into the electricity grid at the full retail energy charge rather than the avoided cost of purchasing those kWh from other energy sources such as NB Power.

TABLE 9
Net Metering Costs

Year		GRA Forecast	Actual	Increase (Decrease) Over GRA
2023	Net Metering Costs	$ 1,874,441	$ 3,440,970	**$ 1,566,529**
	Avoided Cost of Energy Not Required to be Purchased from Other Sources	-	(599,907)	**(599,907)**
	TOTAL	$ 1,874,441	$ 2,841,063	**$ 966,622**
2024	Net Metering Costs	$ 2,304,647	$ 5,026,732	**$ 2,722,085**
	Avoided Cost of Energy Not Required to be Purchased from Other Sources	-	(1,200,600)	**(1,200,600)**
	TOTAL	$ 2,304,647	$ 3,826,132	**$ 1,521,485**
2025[26]	Net Metering Costs	$ 2,770,365	$ 7,293,056	**$ 4,522,691**
	Avoided Cost of Energy Not Required to be Purchased from Other Sources	-	(1,843,588)	**(1,843,588)**
	TOTAL	$ 2,770,365	$ 5,449,468	**$ 2,679,103**

The GRA forecast assumed moderate growth in customer owned net metering solar systems based on historical participation levels. However, actual results reflect a significant increase in installations across PEI, largely attributable to federal and provincial incentive programs during this period. These incentives significantly accelerated customer adoption of roof-top solar and,

[26] The values presented for 2025 include forecast amounts for October, November, and December 2025 as actual data for these months were not finalized at the time this application was prepared.

as a result, the Company was obligated to purchase more energy from net meter customers than forecast in the GRA.

Under the Net Metering Program, the Company must credit customers for excess generation credits at the full retail electricity rate, which is equal to the price charged to customers for consumption. This retail rate recovers not only energy supply but also transmission and distribution costs, administrative and customer service expenses and other regulatory charges. However, when net meter customers deliver energy into the grid, the Company only avoids the cost of buying this energy from other sources. As a result, the retail rate paid to net metered customers is typically higher than the Company's actual savings of purchasing this energy from alternative sources such as NB Power (i.e., the avoided cost).

Accordingly, the combination of (i) the obligation to credit excess customer generation at the full retail rate and (ii) substantially higher-than-forecast program participation has materially increased Net Metering Program costs relative to the forecast. This difference has been appropriately deferred to ECAM.

5.5 EPA Ratchet Costs

The ratchet pricing clause in the EPA, when triggered, adds a premium to the base price per MWh. The ratchet pricing clause is triggered if the actual energy required from March 1 to February 28 of the prior year is more than 6 per cent lower or 8 per cent higher than the forecast energy requirement negotiated in the contract. The premium escalates with every 1 per cent change in the variance. If the ratchet is triggered, the premium is applied to the total energy purchased under the EPA for that year.

The forecast energy requirement was negotiated in the EPA based on the Company's forecast energy requirement prepared in July 2020, which reflected a number of assumptions regarding the amount of energy needed to meet customer demand and how that energy would be sourced.[27] The GRA energy supply information was based on updated information at the time it was prepared including whether the ratchet would be triggered in each year and to what

[27] The negotiated energy levels in the EPA reflected an in-service date of January 1, 2021 for the new 29.4 MW wind farm in eastern PEI, which will not be in service until late 2025.

extent. Actual energy purchases have changed to varying degrees compared to the information available when the GRA forecast was prepared. Such assumptions include the forecast growth in energy sales to customers, lower generation from existing wind farms, the expected in-service date of proposed new wind farms, and the addition of the Slemon Park solar micro grid.

A summary of the ratchet costs forecast and incurred in each of 2023, 2024, 2025 is presented in Table 10.

TABLE 10
EPA Ratchet Costs

Year		GRA Forecast	Actual	Increase (Decrease) Over GRA
2023	EPA Ratchet Costs over GRA Forecast	$ 1,583,518	$ 2,193,719	**$ 610,201**
2024	EPA Ratchet Costs over GRA Forecast	$ 333,385	$ 2,194,309	**$ 1,860,924**
2025[28]	EPA Ratchet Costs over GRA Forecast	$ 788,956	$ 475,122	**$ (313,834)**

The primary reason for the higher-than-forecast results in 2023 was lower wind production due to maintenance issues at the Hermanville wind farm in 2022 requiring higher-than-expected energy purchases under the EPA in 2022, triggering a higher-than-expected ratchet price in 2023.

The increase in the ratchet triggered in 2024 was due to higher-than-expected purchases under the EPA to offset lower-than-expected renewable generation in 2023. This was partly due to the delay in the in-service date of the 10 MW Slemon Park Solar Farm that was expected to be in service for all of 2023 and was not fully operational until April 2024. As well, ongoing maintenance issues at the Hermanville wind farm continued to reduce wind production at that facility in 2023.

[28] The values presented for 2025 include forecast amounts for October, November, and December 2025 as actual data for these months were not finalized at the time of preparing this application.

In 2025, the actual ratchet triggered was less than forecast mainly because the majority of the wind replacement costs associated with the delayed 40 MW wind farm, which was expected to be in-service in 2024, had to be purchased at a premium outside of the EPA. Therefore, the majority of the incremental energy purchases were excluded from the ratchet calculation.

5.6 Capacity Costs

To ensure it can reliably meet customers' energy needs at all times, the Company maintains contractual access to capacity (i.e., the ability to produce or procure electricity when required).[29] The Company holds firm capacity entitlements from Point Lepreau, as well as a capacity and system energy agreement with NB Power delivered through four submarine cables owned by the Province of PEI.

The Company also secures energy and capacity through contracts with the PEI Energy Corporation ("PEIEC") for 129.5 MW of wind generation. However, due to the intermittent nature of wind generation, only a portion of the wind turbine generators' nameplate capacity can be included as a capacity resource for Maritime Electric; this is called the effective load carrying capability. Because Maritime Electric's system peak typically occurs in January or February, either before 8:00 am, which is before sunrise, or after 5:00 p.m., which is after sunset, solar generation facilities do not contribute to Maritime Electric's capacity resources at all.

As shown in Table 11 below, the Company was required to purchase additional capacity above the amounts forecast in the GRA in 2024 and 2025 to meet customer load requirements.

[29] North American Electric Reliability Corporation ("NERC") reliability standards require that utilities ensure the electrical system which they operate is reliable, adequate and secure.

TABLE 11 Capacity Costs				
Year		**GRA Forecast**	**Actual**	**Increase Over GRA**
2023	Capacity Costs	$ 11,687,880	$ 11,687,880	**$ -**
2024	Capacity Costs	$ 13,050,000	$ 13,500,000	**$ 450,000**
2025[30]	Capacity Costs	$ 13,350,000	$ 14,029,965	**$ 679,965**

The upward trend reflects the additional energy purchases required to meet capacity needs beyond the forecasted levels, consistent with the Company's obligation to serve customers under the *Electric Power Act* and the additional cost of capacity has been appropriately deferred to ECAM.

5.7 Non-Spinning Reserve Costs

Non-spinning reserve is a type of backup electricity capacity that is not currently generating power but can be brought online quickly to maintain system reliability if there is a sudden loss of generation or a surge in demand. Unlike spinning reserve, which is already synchronized to the grid and is physically spinning to respond almost instantaneously, non-spinning reserve requires a short period of time to start producing electricity.

10-minute non-spinning reserve

This reserve can be fully online and supplying electricity within approximately 10 minutes of being called upon. It provides a rapid response buffer to cover immediate contingencies on the system.

[30] The values presented for 2025 include forecast amounts for October, November, and December 2025 as actual data for these months were not finalized at the time of preparing this application.

30-minute non-spinning reserve

This reserve can be brought online within about 30 minutes. It provides additional backup capacity to ensure reliability over a slightly longer timeframe, supporting the system while other faster reserves stabilize supply and demand.

These reserves are critical for ensuring that the power system can continue to meet customer demand even if a generator trips offline or unexpected demand occurs, without causing outages.

As shown in Table 12, the Company was required to purchase additional non-spinning reserve above the GRA forecast, due to the February 2023 polar vortex event.

TABLE 12
Non-spinning Reserve Costs

Year		GRA Forecast	Actual	Increase Over GRA
2023	Reserve Costs – 10 Minutes Non-Spinning	$ -	$ 254,446	**$ 254,446**
	Reserve Costs – 30 Minutes Non-Spinning	-	206,106	**206,106**
TOTAL		**$ -**	**$ 460,552**	**$ 460,552**

Non-spinning reserve costs were not forecast nor incurred in 2024 or 2025, therefore no variances are reported for those years. The variance attributable to non-spinning reserve costs for 2023 was appropriately deferred to ECAM.

5.8 Imbalance Costs

Imbalance costs are incurred when scheduled electricity loads do not match actual customer consumption. Imbalance energy accounts for the purchase or sale of energy through the NB System Operator, calculated by comparing actual hourly load to scheduled load and applying the final hourly marginal cost ("FHMC") in New Brunswick. Positive differences create credits or recoveries, while negative differences result in debits or expenses. A summary of the annual imbalances costs is provided in Table 13.

TABLE 13 Imbalance Costs				
Year		**GRA Forecast**	**Actual**	**Increase (Decrease) Over GRA**
2023	Difference in Hourly Energy Purchase Scheduled and Actual Consumed	$ -	$ 894,428	$ 894,428
	Imbalance Purchased/(Sold) at FHMC	-	(1,785,808)	(1,785,808)
	Imbalance Charges/(Recoveries) from Commercial Wind/Solar Participants	-	556,517	556,517
	TOTAL	**$ -**	**$ (334,863)**	**$ (334,863)**
2024	Difference in Hourly Energy Purchase Scheduled and Actual Consumed	$ -	$ 912,778	$ 912,778
	Imbalance Purchased/(Sold) at FHMC	-	(987,533)	(987,533)
	Imbalance Charges/(Recoveries) from Commercial Wind/Solar Participants	-	71,594	71,594
	TOTAL	**$ -**	**$ (3,161)**	**$ (3,161)**
2025[31]	Difference in Hourly Energy Purchase Scheduled and Actual Consumed	$ -	$ 1,149,555	$ 1,149,555
	Imbalance Purchased/(Sold) at FHMC	-	(2,783,398)	(2,783,398)
	Imbalance Charges/(Recoveries) from Commercial Wind/Solar Participants	-	865,577	865,577
	TOTAL	**$ -**	**$ (768,266)**	**$ (768,266)**

As shown in Table 13, imbalance costs are not forecast in the GRA because they are driven by hourly variations in scheduled energy due to customer demand and weather, which are, inherently not forecastable. While the total impact fluctuates annually, these costs remain unpredictable and are managed in real time to ensure reliable electricity supply. The costs have been appropriately deferred to ECAM.

[31] The values presented for 2025 include forecast amounts for October, November, and December 2025 as actual data for these months were not finalized at the time this application was prepared.

5.9 Energy Sales to Third Parties

This amount reflects the recovery of costs associated with energy that the Company acquires or generates and subsequently sells to other third parties, typically other utilities, upon request. The Company does not forecast to provide these sales but fulfills such requests as needed, particularly in emergency or contingency situations.

The energy sold is either procured through the Company's Emergency Energy Transaction contracts or generated at its own generating facilities. Sales are generally recovered from the purchasing party at cost plus a markup, ensuring that the Company and its customers are kept financially whole. An annual summary of energy sales to third parties is provided in Table 14.

TABLE 14
Energy Sales to Third Parties

Year		GRA Forecast	Actual	(Decrease) Over GRA
2023	Energy Sales to Third Parties	$ -	$ (189,222)	**$ (189,222)**
2024	Energy Sales to Third Parties	$ -	$ (64,394)	**$ (64,394)**
2025[32]	Energy Sales to Third Parties	$ -	$(1,168,370)	**$ (1,168,370)**

No amounts were forecast in the GRA as these energy sales are not planned or budgeted but occur on an as-needed basis and the credits are appropriately deferred to ECAM to offset the related costs.

5.10 Interconnection Costs

Under the lease agreements for the subsea cables with the Province of PEI, Maritime Electric is responsible for certain financing, operating and maintenance costs associated with these Government-owned facilities.

32 The values presented for 2025 include forecast amounts for October, November, and December 2025 as actual data for these months were not finalized at the time of preparing this application.

TABLE 15 Interconnection Costs				
Year		**GRA Forecast**	**Actual**	**(Decrease) Over GRA**
2023	Interconnection Costs	$ 4,605,290	$ 4,000,839	**$ (604,451)**
2024	Interconnection Costs	$ 4,630,668	$ 4,143,249	**$ (487,419)**
2025[33]	Interconnection Costs	$ 4,653,006	$ 4,257,876	**$ (395,130)**

As shown in Table 15, actual interconnection costs were below the GRA forecast in each of 2023, 2024, and 2025. The primary driver of these variances is the interconnection lease payments. The year-over-year change in lease costs between 2023 and 2025 reflects a temporary retroactive adjustment to monthly lease payments, applicable from March 2022 to August 2025 that was not finalized until after the GRA was filed and the negotiated settlement agreement with the PEIEC was reached. The savings realized have been appropriately deferred to ECAM.

5.11 Generation Costs

The Company operates and maintains three combustion turbine units on PEI. Two units are located at the Borden Generating Station (CT1 and CT2) and the third is located at the Charlottetown Generating Station (CT3). Specifically, CT1 (15 MW) and CT2 (25 MW) support the assured energy component of the EPA, while CT3 (50 MW) serves as backup for the secure energy component of the EPA.

All three units are forecast to operate primarily in standby and emergency situations, with limited provisional generation included for safety testing and to accommodate potential curtailment of contract energy or transmission constraints in New Brunswick.

[33] The values presented for 2025 include forecast amounts for October, November, and December 2025 as actual data for these months were not finalized at the time this application was prepared.

TABLE 16 Generation Costs				
Year		**GRA Forecast**	**Actual**	**Increase (Decrease) Over GRA**
2023	Generation Fuel Costs	$ 975,510	$ 1,007,686	**$ 32,176**
	Replacement Cost of Energy Generation Produced Below GRA Forecast	-	356,626	**356,626**
	TOTAL	**$ 975,510**	**$ 1,364,312**	**$ 388,802**
2024	Generation Fuel Costs	$ 1,254,434	$ 663,684	**$ (590,750)**
	Replacement Cost of Energy Generation Produced Below GRA Forecast	-	253,815	**253,815**
	TOTAL	**$ 1,254,434**	**$ 917,499**	**$ (336,935)**
2025[34]	Generation Fuel Costs	$ 1,387,297	$ 2,751,407	**$ 1,364,110**
	Avoided Cost of Energy Generation Produced Above GRA Forecast	-	(32,508)	**(32,508)**
	TOTAL	**$ 1,387,297**	**$ 2,718,899**	**$ 1,331,602**

As shown in Table 16, generation fuel costs have fluctuated over the 2023 to 2025 period, reflecting the variability in both combustion turbine usage and diesel fuel pricing. CT3 in particular is being operated during high load system events to provide electrical grid stability.

In addition to fuel cost variances, the energy produced by these units also varied each year. In 2023 and 2024, energy generated was below forecast and the shortfall was procured from other sources. In 2025, generated energy was above the GRA forecast and resulted in avoiding the cost of procuring that energy from other sources. The variances have been appropriately deferred to ECAM.

[34] The values presented for 2025 include forecast amounts for October, November, and December 2025 as actual data for these months were not finalized at the time this application was prepared.

5.12 ECAM Adjustments Related to Variances in Energy Sales

The annual amounts deferred to ECAM are also impacted by energy sales compared to the GRA forecast. Table 17 provides a comparison of actual annual sales to the amounts forecast in the GRA.

TABLE 17 Energy Sales Comparison			
	2023	**2024**	**2025**
GRA Forecast Sales	1,391,748,981	1,412,245,259	1,431,086,983
Actual Sales	1,479,163,879	1,522,950,163	1,580,712,636
Increase over Forecast	**6.3%**	**7.8%**	**10.5%**

Sales increases from the GRA forecast are driven primarily by higher-than-expected residential sales from space heating load. Despite the fact that the number of heating degree days (“HDD”) were lower than normal over the three-year period, space heating load increased due primarily to increased housing starts and increases in government incentives for electrification of space heating over what was forecast in the GRA.

Increases in energy sales above forecast impact the ECAM in two ways. First, the Company must purchase or generate sufficient energy to meet the increase in customer sales. Second, the basic energy charge included in customer rates reflects a forecast of annual energy supply costs based on the Base Rate Cost, as defined in the ECAM and approved by the Commission as described in Section 5.1. For each additional kWh purchased to meet customer sales, the amount collected from customers in basic rates is offset to ECAM by multiplying the kWh purchased by the ECAM base rate presented herein in Table 18.

Table 18 is a summary of the annual impact of the additional cost of energy to meet customer sales beyond the GRA forecast and the additional amounts recovered through customer basic rates due to the increase in sales.

TABLE 18 Impact of Increases in Energy Sales Over GRA Forecast		
Year		**Increase (Decrease) Over GRA**
2023	Additional Energy Purchased to Meet Customer Sales	$ 6,668,089
	Additional Energy Recovered from Customers Through Basic Rates	(8,036,641)
	TOTAL	**$ (1,368,552)**
2024	Additional Energy Purchases to Meet Customer Sales	$ 8,857,350
	Additional Energy Recovered from Customers Through Basic Rates	(10,953,004)
	TOTAL	**$ (2,095,654)**
2025[35]	Additional Energy Purchases to Meet Customer Sales	$ 11,905,622
	Additional Energy Recovered from Customers Through Basic Rates	(15,152,738)
	TOTAL	**$ (3,247,116)**

[35] The values presented for 2025 include forecast amounts for October, November, and December 2025 as actual data for these months were not finalized at the time this application was prepared.

6.0 ECAM COLLECTIONS FROM CUSTOMERS

6.1 Introduction

As summarized in Section 5.1, Table 3 of this Application, the Company's actual ECAM customer collections exceeded the GRA forecast levels in 2023, 2024 and 2025. The following analysis outlines the year-over-year variances in ECAM customer collections and explains the key factors contributing to those differences.

6.2 Monthly ECAM Collected from Customers

Table 19 presents an annual summary of the GRA forecast and the actual annual ECAM customer collections for 2023, 2024, and 2025. Detailed calculations of the monthly ECAM collections to support Table 18 are provided in Appendix B.

ECAM collections are calculated by multiplying the approved ECAM Rate Adjustment by the kWh sales for each month. The variance between the GRA forecast and actual ECAM customer collections represents the amount by which actual collections exceeded (or fell below) the levels projected in the GRA.

TABLE 19
Summary of ECAM Collected from Customers

Year	GRA Forecast kWh Sales	GRA Forecast Customer Collections ($)	Actual kWh Sales	Actual Customer Collections ($)	Increase Over GRA
Reference	**Appendix B Column A**	**Appendix B Column C**	**Appendix B Column D**	**Appendix B Column F**	**Appendix B Column G**
2023	1,391,748,981	$ 7,218,463	1,479,163,879	$ 8,610,353	$ 1,391,890
2024	1,412,245,259	4,912,674	1,522,950,163	10,568,268	5,655,594
2025	1,431,086,983	2,485,518	1,580,712,636	8,101,578	5,616,060
TOTAL		**$ 14,616,655**		**$ 27,280,199**	**$ 12,663,544**

Actual ECAM customer collections exceeded the GRA forecast in 2023, 2024 and 2025. The increases are attributable primarily to two factors. First, actual kWh sales during the period were higher than the levels assumed in the forecast. Second, the Commission approved an additional ECAM Rate Adjustment of $0.0033 per kWh, effective October 1, 2023 (Order UE23-

09) in addition to those approved previously in the GRA Order UE23-04. In Order UE23-09, the Commission ordered the additional collection rate be applied to customer bills until February 28, 2026 or until otherwise varied by the Commission. This addition to the ECAM collection rate resulted in higher collections, beginning in the last quarter of 2023 and continuing throughout 2024 and 2025. Together, higher sales volumes and the additional approved ECAM Rate Adjustment resulted in ECAM customer collections that were $12.6 million higher than forecast in the GRA, and these amounts were appropriately applied to the ECAM balance.

7.0 PROPOSED ECAM RATE ADJUSTMENT

7.1 Introduction

Section N-0 of the Company's Rates and General Rules and Regulations specifies the formula for collection or refund of the ECAM as follows:

> *The ECAM Rate Adjustment applied to Customers' bills shall be calculated as follows and applied to Customers' bills for not less than twelve months unless otherwise Ordered by the Commission.*
>
> 6. *Determine the total of the excess (or deficiency) costs on the Balance Sheet at the end of the third month proceeding the month in which the ECAM rate will be applied.*
> 7. *Determine the forecast total kilowatt hour sales for the twelve month period commencing with the month in which the ECAM rate will be applied.*
> 8. *Divide the amount calculated in (6) above by the amount calculated in (7) above to determine the ECAM rate adjustment required in cents per kilowatt hour sold and which will be applied to Customers' bills. Rate adjustment shall be calculated to the nearest three decimal places (five decimal places on the dollar).*

7.2 Forecast ECAM Balance at December 31, 2025

As discussed in Section 5.1 of this Application and shown in Table 4, the actual ECAM balance was \$11.7 million, \$20.5 million and a forecast \$32.0 million at December 31, 2023, 2024 and 2025, respectively.[36]

In Order UE23-09, the Commission approved the requested ECAM Rate Adjustment of \$0.0033 per kWh, effective October 1, 2023. The \$0.0033 per kWh approved adjustment resulted in a total ECAM collection rate of \$0.00919 per kWh effective October 1, 2023,

[36] The December 31, 2023 and 2024 ECAM balances were reviewed by the Company's external auditors, Deloitte LLP, as part of its year end audit process.

$0.00617 per kWh effective March 1, 2024 and $0.00475 per kWh effective March 1, 2025. This adjustment was set to remain in effect until February 28, 2026, or until further modification by the Commission. The Company has been collecting this adjustment on electricity consumed from October 1, 2023, onward, in addition to the adjustments approved in Order UE23-04.

In this application, the Company is requesting an ECAM Rate Adjustment effective March 1, 2026 to recover the remaining $31.9 million balance in ECAM as of December 31, 2025.

7.3 Proposed ECAM Rate Adjustment Applied to Customers' Bills

The Company is proposing that the ECAM Collection Rate of $0.01949 per kWh, as shown in Table 20, be applied to customers' bills effective March 1, 2026 and remain in effect until February 28, 2027, or as otherwise ordered by the Commission.

TABLE 20
Proposed Increase to the ECAM Rate Adjustment to Customers' Bills

			2023	2024	2025	TOTAL
Additional ECAM Balance to be Collected from Customers, Dec 31, 2022	Order UE23-09	A	$ -	$ -	$ -	$ 4,864,230
Additional Energy Costs Deferred to ECAM over GRA Forecast	Sec 5.1, Table 2	B	4,145,205	16,509,314	19,013,368	39,667,887
Excess in Actual ECAM Collections compared to GRA Forecast	Sec 5.1, Table 3	C	(1,391,890)	(5,655,594)	(5,616,060)	(12,663,544)
Additional ECAM Balance to be Collected from Customers, Dec 31		**D=A+B+C**	**2,753,315**	**10,853,719**	**13,397,309**	**31,868,573**
GRA Forecast ECAM Balance, Dec 31, 2025	Sec 5.1, Table 4	E	-	-	-	112,471
TOTAL ECAM Balance, Dec 31, 2025 to be Collected from Customers – Mar 1, 2026, to Feb 28, 2027		**F=D+E**	**-**	**-**	**-**	**31,981,044**
Forecast kWh Sales – Mar 1, 2026, to Feb 28, 2027	Sec 7.4, Table 21	G	-	-	-	1,640,485,000
Proposed ECAM Rate Adjustment		**H=F/G**	**$ -**	**$ -**	**$ -**	**$ 0.01949**

7.4 Forecast kWh Sales from March 1, 2026 to February 28, 2027

Table 21 provides a comparison of the actual and forecast kWh sales for the twelve months ending February 28, 2026 to the forecast kWh sales over the proposed ECAM Rate Adjustment collection period of March 1, 2026 to February 28, 2027. [37]

TABLE 21
Forecast kWh Sales

Class	Consumption Period		Forecast Growth
	March 1, 2025 to February 28, 2026	March 1, 2026 to February 28, 2027	
Residential	878,265,600	942,157,600	7.3%
General Service	431,123,800	432,699,100	0.4%
Large Industrial	162,291,000	165,636,100	2.1%
Small Industrial	94,216,100	93,815,000	(0.4)%
Street Lighting	3,515,700	3,506,800	(0.3)%
Unmetered	2,638,600	2,670,400	1.2%
TOTAL SALES	**1,572,050,800**	**1,640,485,000**	**4.4%**

The forecast sales for the period March 1, 2026, to February 28, 2027 is based on the Company's most recent customer load forecast updated in October 2025. This forecast is based on a methodology consistent with the forecast provided in the Company's previous GRA and was reviewed by Grant Thornton in 2020.

The residential sales forecast integrates housing starts projections from the Conference Board of Canada to forecast load growth from new construction. Housing starts are categorized by type of dwelling (e.g., single-family detached, semi-detached and multi-family), each of which is associated with distinct electricity usage levels.

The forecast accounts for changes in space heating load driven by new housing starts and heat pump installations, which is primarily supported by Government programs. Space heating load is also dependent on the number of HDD during the heating season; the forecast is based on the ten-year average number of HDD.

[37] The forecast for the twelve months ended February 28, 2026 reflects actual sales from March 2025 (prorated) to September 2025 and forecast sales from October 1, 2025 to February 28, 2026 plus March 2026 (prorated).

Non-space heating load forecasts incorporate reductions from efficiencyPEI's demand side management programs and net metering solar installations. Overall, the forecast anticipates a steady increase in residential energy sales, primarily from new housing developments, with adjustments for energy efficiency initiatives and net metering solar installations.

The General Service, Small Industrial and Unmetered sales forecasts are based on the Conference Board of Canada's assessment of PEI's forecast gross domestic product growth.

The Large Industrial rate class is currently comprised of seven large industrial customers. The forecast reflects energy sales trends from 2022 to 2024, along with any known customer planned expansions.

Street Lighting sales have continuously declined since 2014 as the Company converts existing streetlights with more energy efficient light-emitting diode ("LED") streetlights. The forecast reflects a continued decrease.

7.5 Forecast ECAM Collection from Customer from March 1, 2026 to February 28, 2027

The forecast monthly ECAM collection from customers from March 1, 2026 to February 28, 2027 is provided in Table 22. The monthly collection of ECAM is the product of the proposed ECAM Rate Adjustment per kWh per Table 20 and the forecast kWh energy sales per Table 21.

TABLE 22 Monthly ECAM Collected from Customers			
Collection Month	**Forecast kWh Sales**	**ECAM Rate Adjustment per kWh**	**ECAM Collected from Customers**
March 2026[38]	77,632,100	$ 0.01949	$ 1,513,429
April 2026	144,455,000	0.01949	2,816,132
May 2026	127,893,200	0.01949	2,493,261
June 2026	115,387,800	0.01949	2,249,470
July 2026	117,627,100	0.01949	2,293,125
August 2026	128,388,700	0.01949	2,502,921
September 2026	120,433,500	0.01949	2,347,836
October 2026	108,805,400	0.01949	2,121,147
November 2026	123,633,300	0.01949	2,410,215
December 2026	155,156,000	0.01949	3,024,746
January 2027	168,463,900	0.01949	3,284,182
February 2027	173,299,400	0.01949	3,378,449
March 2027[36]	79,309,600	0.01949	1,546,131
TOTAL	**1,640,485,000**	**$ 0.01949**	**$ 31,981,044**

The forecast kWh sales in Tables 21 and 22 are based on the methodology described in Section 7.4 of this Application. To the extent that actual kWh sales vary from the forecast, any difference between the actual amount of ECAM collected from customers and the amounts forecast in Table 22 will be deferred in the ECAM account to be collected or refunded to customers in a future period. This approach is consistent with the operation of the ECAM in previous years.

[38] The proposed ECAM Rate Adjustment will be prorated on customer bills based on consumption period as set out in the Commission's letter of direction dated January 22, 2021.

8.0 CUSTOMER IMPACT

8.1 Proposed Customer Rates

Appendix B provides a schedule of existing customer rates, by customer class, effective March 1, 2025 and the proposed customer rates for March 1, 2026 based on this Application. A summary comparison of the existing and proposed per kWh charge by customer class is provided in Table 23.

TABLE 23		
Energy Charge per kWh - Revenue Requirement (A)		
Customer Class	**1-Mar-25**	**1-Mar-26**
Residential - First Block	$ 0.1663	$ 0.1663
Residential - Second Block	$ 0.1315	$ 0.1315
General Service - First Block	$ 0.2053	$ 0.2053
General Service - Second Block	$ 0.1329	$ 0.1329
Small Industrial - First Block	$ 0.2009	$ 0.2009
Small Industrial - Second Block	$ 0.0995	$ 0.0995
Large Industrial	$ 0.0830	$ 0.0830
Energy Charges per kWh – Other Amounts (B)		
Description	**1-Mar-25**	**1-Mar-26**
ECAM Charge per kWh		
Approved Order UE23-04 and UE23-09	$ 0.00475	$ -
Proposed March 1, 2026 Adjustment	-	$ 0.01949
Total ECAM Charge per kWh	**$ 0.00475**	**$ 0.01949**
Provincial Energy Efficiency and Conservation (“EE&C”) Plan per kWh approved in Order UE23-04	$ 0.00121	$ 0.00121
Total Energy Charge per kWh – Other Amounts	**$ 0.00596**	**$ 0.02070**
Total Energy Charge per kWh (A + B)		
Customer Class	**1-Mar-25**	**1-Mar-26**
Residential - First Block	$ 0.1723	$ 0.1870
Residential - Second Block	$ 0.1375	$ 0.1522
General Service - First Block	$ 0.2113	$ 0.2260
General Service - Second Block	$ 0.1389	$ 0.1536
Small Industrial - First Block	$ 0.2069	$ 0.2216
Small Industrial - Second Block	$ 0.1055	$ 0.1202
Large Industrial	$ 0.0890	$ 0.1037

8.2 Impact on Annual Customer Costs

The proposed ECAM Rate Adjustment will increase the monthly energy charge per kWh as shown in Table 24 and Appendix C. Other customer charges, namely the monthly service charges, other components of the energy charge, and demand charges, will remain unchanged.

Table 24 illustrates estimated annual cost, by component, for a benchmark rural residential customer using 1,000 kWh per month, or 12,000 kWh per year.

TABLE 24 Annual Cost for Rural Residential Customer (1,000 kWh per Month/12,000 kWh per Year)		
	Approved UE23-04 and UE23-09 March 1, 2025	**Proposed March 1, 2026**
Service Charge	$ 323.04	$ 323.04
Basic Energy Charge	1,995.60	1,995.60
ECAM Charge	**57.00**	**233.88**
Provincial Energy Efficiency and Conservation Plan	14.52	14.52
Sub-total	**2,390.16**	**2,567.04**
HST	358.52	385.06
Provincial Clean Energy Rebate[39]	(206.71)	(224.40)
Total Annual Cost	**$ 2,541.97**	**$ 2,727.70**
Percentage Annual Increase (%)		
Before Tax		**7.4%**
After Tax		**7.3%**

[39] The Provincial Clean Energy Rebate is a provincial Government rebate on the first block energy up to 2,000 kWh per month for eligible Residential year-round customers.

Table 25 illustrates the estimated annual cost, by component, for a benchmark urban residential customer using 1,000 kWh per month, or 12,000 kWh per year.

TABLE 25 Annual Cost for Urban Residential Customer (1,000 kWh per Month/12,000 kWh per Year)		
	Approved UE23-04 and UE23-09 March 1, 2025	**Proposed March 1, 2026**
Service Charge	$ 294.84	$ 294.84
Basic Energy Charge	1,995.60	1,995.60
ECAM Charge	**57.00**	**233.88**
Provincial Energy Efficiency and Conservation Plan	14.52	14.52
Sub-total	**2,361.96**	**2,538.84**
HST	354.29	380.83
Provincial Clean Energy Rebate	(206.71)	(224.40)
Total Annual Cost	**$ 2,509.54**	**$ 2,695.27**
Percentage Annual Increase (%)		
Before Tax		**7.5%**
After Tax		**7.4%**

Table 26 illustrates the estimated annual cost, by component, for a general service customer using 10,000 kWh per month, or 600,000 kWh per year, and demand of 50 kW per month, or 600 KW per year.

TABLE 26 Annual Cost for General Service Customer (10,000 kWh/50 KW per Month/120,000 kWh/600 KW per Year)		
	Approved UE23-04 and UE23-09 March 1, 2025	**Proposed March 1, 2026**
Service Charge	$ 294.84	$ 294.84
Demand Charge	4,834.80	4,834.80
Basic Energy Charge	20,292.00	20,292.00
ECAM Charge	**570.00**	**2,338.80**
Provincial Energy Efficiency and Conservation Plan	145.20	145.20
Sub-total	**26,136.84**	**27,905.64**
HST	3,920.53	4,185.85
Total Annual Cost	**$ 30,057.37**	**$ 32,091.49**
Percentage Annual Increase (%)		
Before Tax		**6.8%**
After Tax		**6.8%**

Benchmark customers in the Small and Large Industrial classes will experience slightly larger increases in annual electricity costs than those presented for Residential and General Service Customers. This is due to the lower per kWh charge for the Large Industrial class and lower second block charge for the Small Industrial class, as the proposed ECAM Rate Adjustment represents a larger percentage increase on these lower rates. The impact for each individual customer will vary depending upon each customers' demand and consumption profile. However, a reasonable estimate would be an increase of 9.0 per cent for Small Industrial Customers and 13.0 to 14.0 per cent for Large Industrial customers.

9.0 CONCLUSION

The Company's proposed ECAM Rate Adjustment is necessary to recover material cost variances that were not anticipated in the GRA forecast. Over 75 per cent of the additional energy costs deferred to the ECAM account relate to replacement energy purchases resulting from unplanned outages at Point Lepreau. The facility experienced more outage days than forecasted in all three years, requiring the Company to purchase alternative energy supplies to meet customer demand. A further 10 per cent of the additional energy costs deferred to ECAM over the GRA forecast relates to higher-than-forecast OM&A costs at Point Lepreau. These costs continued to be incurred even while the facility was not producing energy, partially offset by lower-than-forecast fuel use.

Net metering costs account for approximately 13 per cent of the additional energy costs deferred to ECAM over the GRA forecast, driven by a surge in customer-owned solar installations across the province. As required by legislation, the Company must credit excess customer generation at the full retail electricity rate, and both the higher export volumes and the purchase rate have contributed to a significant increase in program costs.

Additionally, approximately 8 per cent of the additional energy costs deferred to ECAM over the GRA forecast relates to wind energy costs due to lower wind production at the existing Hernanville wind farm due to maintenance issues as well as two wind farms forecasted to be in service during the period were delayed, requiring the Company to secure wind replacement energy that exceeded the savings in wind energy purchase costs.

While actual customer collections through the ECAM were higher than forecast, these additional collections were not sufficient to offset the above cost variances. As a result, the ECAM account recorded a receivable balance of approximately $32.0 million at December 31, 2025, exceeding the GRA forecast by $31.9 million.

To recover this balance, the Company is requesting approval of a $0.01949 per kWh ECAM Rate Adjustment, effective March 1, 2026, for all customer classes. This adjustment will enable recovery of the deferred balance over the period March 1, 2026 through February 28, 2027, in accordance with Section N-0 of the Company's Rates and General Rules and Regulations. The proposed collection of the ECAM account balance will reduce the magnitude of customer rate adjustments that would otherwise occur in the next GRA.

The proposed collection of the ECAM account balance also reduces the overall financing costs for customers, as the Company will be financing a lower ECAM balance compared to carrying the full amount on its balance sheet until the next GRA rate adjustment.

10.0 PROPOSED ORDER

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of Section 3(a), 10, 13(1) and 20 of the *Electric Power Act* (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order approving an Energy Cost Adjustment Mechanism rate adjustment to customers' bills for the period March 1, 2026 to February 28, 2027 and for certain approvals incidental to such an order.

WHEREAS on or about September 27, 2019 the Commission issued Order UE19-08;

AND WHEREAS pursuant to Order UE19-08, Maritime Electric filed a comprehensive review of the ECAM, on or about June 1, 2020;

AND WHEREAS on or about July 28, 2021 the Commission issued Order UE21-05 approving the continued operation of the ECAM with revisions effective the next rate setting period but not approving the automatic resetting the ECAM Rate Adjustment applied to customers' bills;

AND WHEREAS the Company's forecast ECAM balance of $32.0 million on December 31, 2025 is $31.9 million higher than forecast in the GRA, primarily due to the costs incurred as a result of extended or unplanned outages at Point Lepreau, wind replacement energy costs, increased net metering program costs and other energy cost variances as described in Section

5 of the Application that were partially offset by higher than forecast collections from the ECAM Rate Adjustment as described in Section 6 of the Application;

NOW AND THEREFORE pursuant to the *Electric Power Act* and the *Island Regulatory and Appeals Commission Act*, the Commission orders as follows:

IT IS ORDERED THAT:

Maritime Electric shall collect an ECAM Rate Adjustment beginning on March 1, 2026 until February 28, 2027 or until otherwise approved by the Commission, at the rate of $0.01949 in accordance with Section N-0 of the Company's Rates and General Rules and Regulations.

DATED at Charlottetown this ____ day of __________, 2026.

BY THE COMMISSION

________________________________,

Chair

____

Commissioner

____

Commissioner

APPENDIX A

2023, 2024 and 2025 Energy Cost Adjustment Mechanism Continuity Schedule

2023 Monthly ECAM Schedule													
Energy Cost Adjustment Mechanism	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**TOTAL**
Gross Energy Costs (Page 6, 2 of 2)[1]	18,027,854	13,883,556	14,051,908	12,497,500	12,523,536	10,448,070	12,007,003	11,377,206	10,708,328	11,429,767	12,679,966	14,031,285	153,665,979
Non ECAM Energy:													
Less Production - other (Page 6, 2 of 2)[1, 2]	(86,066)	(85,649)	(86,953)	(87,115)									(345,783)
Add Amortization - other (Page 2)[1, 3]	14,405	14,405	14,405	(12,083)									31,132
Total Energy Purchase Cost - ECAM	17,956,193	13,812,312	13,979,360	12,398,302	12,523,536	10,448,070	12,007,003	11,377,206	10,708,328	11,429,767	12,679,966	14,031,285	153,351,328
Net Purchased & Produced Energy - kWh (Page 13)[1]	157,290,588	156,570,639	149,540,134	122,627,811	116,581,575	111,621,411	127,831,468	119,472,733	110,544,083	116,866,554	141,105,016	156,391,595	1,586,443,607
Base Rate/kWh	0.09244	0.09244	0.09244	0.09244	0.09050	0.09050	0.09050	0.09050	0.09050	0.09050	0.09050	0.09050	0.0912166322135017
Base Energy Costs	14,539,942	14,473,390	13,823,490	11,335,715	10,550,633	10,101,738	11,568,748	10,812,282	10,004,240	10,576,423	12,770,004	14,153,439	144,710,043
Difference Between Actual and Base Energy Costs	3,416,251	(661,078)	155,870	1,062,587	1,972,903	346,332	438,255	564,924	704,088	853,344	(90,038)	(122,154)	8,641,285
ECAM Opening Balance	11,655,299	14,501,151	13,243,314	12,838,637	13,365,230	14,727,210	14,445,601	14,228,963	14,111,519	14,174,924	14,249,406	13,090,461	11,655,299
Additions/(Reductions)	3,416,251	(661,078)	155,870	1,062,587	1,972,903	346,332	438,255	564,924	704,088	853,344	(90,038)	(122,154)	8,641,285
Rebated/(Collected) From Ratepayer	(570,399)	(596,759)	(560,547)	(535,994)	(610,924)	(627,941)	(654,892)	(682,368)	(640,684)	(778,862)	(1,068,907)	(1,282,075)	(8,610,353)
Balance ECAM Effective for Rates	14,501,151	13,243,314	12,838,637	13,365,230	14,727,210	14,445,601	14,228,963	14,111,519	14,174,924	14,249,406	13,090,461	11,686,231	11,686,231
Rebated/(Collected) From Ratepayer													
Energy Sales - kWh (Page 12)[1]	141,890,371	148,447,463	139,439,604	133,331,813	114,119,479	106,611,426	111,187,167	115,851,908	108,774,864	103,690,120	116,312,004	139,507,660	1,479,163,879
ECAM Adjustment Rate per kWh	0.00402	0.00402	0.00402	0.00402	0.00535	0.00589	0.00589	0.00589	0.00589	0.00751	0.00919	0.00919	0.00582
Balance ECAM Effective for Rates	570,399	596,759	560,547	535,994	610,924	627,941	654,892	682,368	640,684	778,862	1,068,907	1,282,075	8,610,353

2024 Monthly ECAM Schedule													
Energy Cost Adjustment Mechanism	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**TOTAL**
Purchased Energy Costs	12,129,897	10,503,351	9,717,983	9,098,368	9,157,155	8,534,028	9,810,703	9,848,917	8,403,006	9,205,727	10,089,592	12,657,115	119,155,842
Lepreau Energy Costs	1,925,290	2,146,790	2,297,402	962,093	1,821,027	1,985,814	1,764,662	1,601,392	2,440,797	3,729,057	2,564,852	2,456,161	25,695,337
Renewable Energy Costs	2,054,937	2,037,078	2,228,434	2,325,856	1,881,274	2,134,752	2,174,439	1,792,805	2,196,396	2,526,411	3,173,698	2,404,938	26,931,018
On-Island Generation	49,732	79,447	39,172	46,744	11,469	18,276	-	52,920	13,769	11,951	152,408	205,706	681,594
Total Energy Purchase Cost - ECAM (Page 6, 1 of 2)[1]	16,159,856	14,766,666	14,282,991	12,433,061	12,870,925	12,672,870	13,749,804	13,296,034	13,053,968	15,473,146	15,980,550	17,723,920	172,463,791
Net Purchased & Produced Energy - kWh (Page 13)[1]	177,222,700	158,341,233	149,459,808	127,269,637	117,273,204	112,476,672	126,718,458	127,508,409	108,840,060	123,178,345	136,250,602	170,413,591	1,634,952,719
Base Rate/kWh	0.09050	0.09050	0.09440	0.09440	0.09440	0.09440	0.09440	0.09440	0.09440	0.09440	0.09440	0.09440	0.09360
Base Energy Costs	16,038,654	14,329,882	14,109,006	12,014,254	11,070,590	10,617,798	11,962,222	12,036,794	10,274,502	11,628,036	12,862,057	16,087,043	153,030,837
Difference Between Actual & Base Energy Costs	121,202	436,784	173,985	418,807	1,800,335	2,055,072	1,787,582	1,259,240	2,779,466	3,845,110	3,118,493	1,636,877	19,432,954
ECAM Opening Balance	11,686,231	10,412,363	9,363,988	8,427,796	8,036,798	9,093,950	10,478,773	11,593,738	12,103,879	14,188,931	17,383,016	19,770,495	**11,686,231**
Additions/(Reductions)	121,202	436,784	173,985	418,807	1,800,335	2,055,072	1,787,582	1,259,240	2,779,466	3,845,110	3,118,493	1,636,877	19,432,954
Rebated/(Collected) From Ratepayer	(1,395,070)	(1,485,160)	(1,110,177)	(809,806)	(743,182)	(670,249)	(672,617)	(749,099)	(694,415)	(651,025)	(731,015)	(856,456)	(10,568,268)
Balance ECAM Effective for Rates	10,412,363	9,363,988	8,427,796	8,036,798	9,093,950	10,478,773	11,593,738	12,103,879	14,188,931	17,383,016	19,770,495	20,550,916	**20,550,917**
Rebated/(Collected) From Ratepayer													
Energy Sales - kWh (Page 12)[1]	151,803,020	161,606,065	143,436,991	131,248,896	120,450,943	108,630,244	109,014,180	121,409,828	112,546,943	105,514,512	118,478,863	138,809,678	1,522,950,163
ECAM Adjustment Rate per kWh	0.00919	0.00919	0.00774	0.00617	0.00617	0.00617	0.00617	0.00617	0.00617	0.00617	0.00617	0.00617	0.00694
Balance ECAM Effective for Rates	1,395,070	1,485,160	1,110,177	809,806	743,182	670,249	672,617	749,099	694,415	651,025	731,015	856,456	10,568,268

2025 Monthly ECAM Schedule													
Energy Cost Adjustment Mechanism	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25[4]**	**Nov-25[4]**	**Dec-25[4]**	**TOTAL**
Total Energy Purchase Cost - ECAM (Page 6, 1 of 2)[1]	18,185,529	17,262,889	14,896,361	13,715,997	12,253,890	12,443,164	13,853,532	15,046,438	14,823,153	14,627,225	16,168,997	18,691,975	181,969,150
Net Purchased & Produced Energy - kWh (Page 13)[1]	187,265,634	171,708,251	154,872,837	134,475,447	122,142,596	112,555,381	126,302,676	126,809,902	123,514,192	113,408,172	154,386,275	168,928,023	1,696,369,386
Base Rate/kWh	0.09440	0.09440	0.09612	0.09612	0.09612	0.09612	0.09612	0.09612	0.09612	0.09612	0.09612	0.09612	0.09576
Base Energy Costs	17,677,876	16,209,259	14,886,377	12,925,780	11,740,346	10,818,823	12,140,067	12,188,968	11,872,184	10,900,794	14,839,609	16,237,362	162,437,444
Difference Between Actual & Base Energy Costs	507,653	1,053,630	9,984	790,217	513,544	1,624,341	1,713,465	2,857,470	2,950,969	3,726,432	1,329,388	2,454,614	19,531,706
ECAM Opening Balance	20,550,916	20,050,045	19,965,244	19,185,218	19,337,178	19,267,038	20,367,086	21,558,309	23,840,112	26,257,657	29,477,011	30,231,911	20,550,916
Additions/(Reductions)	507,653	1,053,630	9,984	790,217	513,544	1,624,341	1,713,465	2,857,470	2,950,969	3,726,432	1,329,388	2,454,614	19,531,706
Rebated/(Collected) From Ratepayer	(1,008,524)	(1,138,431)	(790,010)	(638,257)	(583,683)	(524,292)	(522,242)	(575,668)	(533,424)	(507,077)	(574,489)	(705,480)	(8,101,578)
Balance ECAM Effective for Rates	20,050,045	19,965,244	19,185,218	19,337,178	19,267,038	20,367,086	21,558,309	23,840,112	26,257,657	29,477,011	30,231,911	31,981,044	**31,981,044**
Rebated/(Collected) From Ratepayer	1,008,524	1,138,431	790,010	638,257	583,683	524,292	522,242	575,668	533,424	507,077	574,489	705,480	
Energy Sales - kWh (Page 12)[1]	163,456,132	184,510,681	145,458,954	134,369,956	122,880,714	110,377,339	109,945,752	121,193,159	112,299,750	106,753,079	120,945,029	148,522,093	1,580,712,637
ECAM Adjustment Rate per kWh	0.00617	0.00617	0.00543	0.00475	0.00475	0.00475	0.00475	0.00475	0.00475	0.00475	0.00475	0.00475	0.00513
Balance ECAM Effective for Rates	1,008,524	1,138,431	790,010	638,257	583,683	524,292	522,242	575,668	533,424	507,077	574,489	705,480	8,101,578

[1] The page references correspond to the Company's monthly reports submitted to IRAC.
[2] Production - other includes insurance, property tax and training.
[3] Amortization - other is the amortization of the Point Lepreau Writedown
[4] The values presented for October, November, and December 2025 represent forecasted amounts, given that actual data for these months were not finalized at the time of preparing this application.

APPENDIX B

Monthly ECAM Collections from Customers

Monthly ECAM Collected from Customers							
Collection Month	GRA Forecast kWh Sales	GRA Forecast ECAM Rate Adjustment ($/kWh)	GRA Forecast Customer Collections ($)	Actual kWh Sales	Actual ECAM Rate Adjustment ($/kWh)	Actual Customer Collections ($)	Increase (Decrease) Over GRA
	A	B	C = A x B	D	E	F = D x E	G = F - C
January-23	139,765,735	0.00402	$ 561,858	141,890,371	0.00402	$ 570,399	8,541
February-23	140,318,314	0.00402	564,080	148,447,463	0.00402	596,759	32,679
March-23	126,276,758	0.00402	507,633	139,439,604	0.00402	560,547	52,915
April-23	117,135,819	0.00402	470,886	133,331,813	0.00402	535,994	65,108
May-23[1]	110,140,476	0.00589	648,727	114,119,479	0.00535	610,924	(37,803)
June-23	102,675,407	0.00589	604,758	106,611,426	0.00589	627,941	23,183
July-23	101,287,129	0.00589	596,581	111,187,167	0.00589	654,892	58,311
August-23	111,404,739	0.00589	656,174	115,851,908	0.00589	682,368	26,194
September-23	104,369,273	0.00589	614,735	108,774,864	0.00589	640,684	25,949
October-23[1]	100,720,228	0.00589	593,242	103,690,120	0.00751	778,862	185,619
November-23	113,671,527	0.00589	669,525	116,312,004	0.00919	1,068,907	399,382
December-23	123,983,577	0.00589	730,263	139,507,660	0.00919	1,282,075	551,812
Total	**1,391,748,981**		**$ 7,218,463**	**1,479,163,879**		**$ 8,610,353**	**$ 1,391,890**
January-24	142,032,551	0.00589	836,572	151,803,020	0.00919	1,395,070	558,498
February-24	142,580,221	0.00589	839,798	161,606,065	0.00919	1,485,160	645,362
March-24[1]	128,237,772	0.00287	368,042	143,436,991	0.00774	1,110,177	742,134
April-24	118,916,503	0.00287	341,290	131,248,896	0.00617	809,806	468,515
May-24	111,825,763	0.00287	320,940	120,450,943	0.00617	743,182	422,242
June-24	104,120,798	0.00287	298,827	108,630,244	0.00617	670,249	371,422
July-24	102,666,028	0.00287	294,652	109,014,180	0.00617	672,617	377,966
August-24	112,872,932	0.00287	323,945	121,409,828	0.00617	749,099	425,153
September-24	105,824,902	0.00287	303,717	112,546,943	0.00617	694,415	390,697
October-24	102,160,880	0.00287	293,202	105,514,512	0.00617	651,025	357,823
November-24	115,343,068	0.00287	331,035	118,478,863	0.00617	731,015	399,980
December-24	125,663,841	0.00287	360,655	138,809,678	0.00617	856,456	495,800
Total	**1,412,245,259**		**$ 4,912,674**	**1,522,950,163**		**$ 10,568,268**	**$ 5,655,594**
January-25	144,234,333	0.00287	413,953	163,456,132	0.00617	1,008,524	594,572
February-25	144,808,946	0.00287	415,602	184,510,680	0.00617	1,138,431	722,829
March-25[1]	130,175,659	0.00145	188,755	145,458,954	0.00543	790,010	601,255
April-25	120,615,451	0.00145	174,892	134,369,956	0.00475	638,257	463,365
May-25	113,389,932	0.00145	164,415	122,880,714	0.00475	583,683	419,268
June-25	105,397,044	0.00145	152,826	110,377,339	0.00475	524,292	371,467
July-25	103,847,129	0.00145	150,578	109,945,752	0.00475	522,242	371,664
August-25	114,208,390	0.00145	165,602	121,193,159	0.00475	575,668	410,065
September-25	107,014,695	0.00145	155,171	112,299,750	0.00475	533,424	378,253
October-25	103,412,312	0.00145	149,948	106,753,079	0.00475	507,077	357,129
November-25	116,873,095	0.00145	169,466	120,945,029	0.00475	574,489	405,023
December-25	127,109,996	0.00145	184,309	148,522,093	0.00475	705,480	521,170
Total	**1,431,086,983**		**$ 2,485,518**	**1,580,712,636**		**$ 8,101,578**	**$ 5,616,060**

[1]The ECAM Rate Adjustment was prorated on customer bills based on consumption period as set out in the Commission's letter of direction dated January 22, 2021.

MARITIME ELECTRIC
A FORTIS COMPANY
All our energy.
All the time.

APPENDIX C

Section N-28
Schedule of Proposed Rates

Maritime Electric Company, Limited Schedule of Rates			
Rate Code		**March 1, 2025**	**March 1, 2026**
110	**Residential**		
	Service Charge	$ 24.57	$24.57
	Energy Charge per kWh for first 2,000 kWh	$ 0.1723	$ 0.1870
	Energy Charge per kWh for balance kWh	$ 0.1375	$ 0.1522
130	**Residential Rural**		
	Service Charge	$ 26.92	$26.92
	Energy Charge per kWh for first 2,000 kWh	$ 0.1723	$ 0.1870
	Energy Charge per kWh for balance kWh	$ 0.1375	$ 0.1522
131	**Residential Seasonal**		
	Service Charge	$ 26.92	$ 26.92
	Energy Charge per kWh for first 2,000 kWh	$ 0.1723	$ 0.1870
	Energy Charge per kWh for balance of kWh	$ 0.1375	$ 0.1522
133	**Residential Seasonal Option**		
	Service Charge	$ 37.50	$37.50
	Energy Charge per kWh for first 2,000 kWh	$ 0.1723	$ 0.1870
	Energy Charge per kWh for balance of kWh	$ 0.1375	$ 0.1522
232	**General Service**		
	Service Charge	$ 24.57	$24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.2113	$ 0.2260
	Energy Charge per kWh for balance of kWh	$ 0.1389	$ 0.1536
233	**General Service - Seasonal Operators Option**		
	Service Charge	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.2113	$ 0.2260
	Energy Charge per kWh for balance of kWh	$ 0.1389	$ 0.1536
320	**Small Industrial**		
	Demand Charge - per kW	$ 7.46	$7.46
	Energy Charge per kWh for first 100 kWh per kW billing demand	$ 0.2069	$ 0.2216
	Energy Charge per kWh for balance of kWh	$ 0.1055	$ 0.1202
310	**Large Industrial**		
	Demand Charge per kW	$ 14.50	$ 14.50
	Energy Charge per kWh	$ 0.0890	$ 0.1037
340	**Long Term Contract** (Currently no customers in this rate category)		
	Demand Charge per kW	$ 15.51	$ 15.51
	Energy Charge per kWh	$ 0.1165	$ 0.1312
330	**Short Term Contract** (Currently no customers in this rate category)		
	Demand Charge - per kW	$ 16.79	$ 16.79
	Energy Charge per kWh for all kWh in the first block	$ 0.1154	$ 0.1301
	Energy Charge per kWh for balance of kWh in the month	$ 0.0961	$ 0.1108

Maritime Electric Company, Limited
Schedule of Rates

	Residential	Type		Annual kWh	Monthly kWh		March 1, 2025		March 1, 2026
	619	LED	70 W HPS Equivalent St Lights - Rented		15	$	13.55	$	13.76
	625	LED	100 W HPS Equivalent St Lights - Rented		17	$	14.03	$	14.27
*	630	HPS	St Lights - Rented	389	32	$	18.02	$	18.48
*	631	HPS	St Lights - Rented	553	46	$	22.92	$	23.60
*	632	HPS	St Lights - Rented	799	66	$	32.78	$	33.75
	633	HPS	St Lights - Rented	1283	106	$	44.69	$	46.25
	634	HPS	St Lights - Rented	1886	157	$	52.52	$	54.83
*	635	MV	St Lights - Rented	656	54	$	18.02	$	18.82
	639	Lanterns	City Lanterns - Rented	389	32	$	65.58	$	66.04
*	640	HPS	St Lights - Owned	389	32	$	7.23	$	7.69
*	641	HPS	St Lights - Owned	553	46	$	9.56	$	10.24
*	642	HPS	St Lights - Owned	779	65	$	12.86	$	13.83
	643	HPS	St Lights - Owned	1283	107	$	20.41	$	21.99
	644	HPS	St Lights - Owned	1886	157	$	32.11	$	34.42
	651	LED	St Lights - Owned	78	7	$	1.31	$	1.41
	652	LED	St Lights - Owned	246	21	$	4.13	$	4.43
	653	LED	St Lights - Owned	205	17	$	3.44	$	3.68
	666	LED	175 W MV Equivalent St Lights - Rented		25	$	15.65	$	16.01
*	670	LED	St Lights - Rented	410	34	$	18.24	$	18.75
*	675	LED	150 W/200 W HPS Equivalent St Lights - Rented		37	$	16.99	$	17.54
*	719	LED	St Lights - Owned	176	15	$	2.96	$	3.17
	730	HPS	Yard Lights - Rented	389	32	$	18.02	$	18.48
	731	HPS	Yard Lights - Rented	553	46	$	22.92	$	23.60
*	732	HPS	Yard Lights - Rented	799	66	$	32.78	$	33.75
*	733	HPS	Yard Lights - Rented	1283	106	$	44.69	$	46.25
*	734	HPS	Yard Lights - Rented	1886	157	$	52.52	$	54.83
*	735	MV	Yard Lights - Rented	656	54	$	18.02	$	18.82
	740	HPS	Yard Lights - Owned	389	32	$	7.23	$	7.69
	741	HPS	Yard Lights - Owned	553	46	$	9.56	$	10.24
	742	HPS	Yard Lights - Owned	779	65	$	12.86	$	13.83
	743	HPS	Yard Lights - Owned	1283	107	$	20.41	$	21.99
	744	HPS	Yard Lights - Owned	1886	157	$	32.11	$	34.42
	749	LPS	Yard Lights - Owned	869	72	$	14.97	$	16.03
	753	Flood	Yard Lights - Rented	1283	107	$	42.69	$	44.27
	754	Flood	Yard Lights - Rented	1886	157	$	53.32	$	55.63
	755	Halide	Yard Lights - Rented	1148	95	$	44.82	$	46.23
	756	Halide	Yard Lights - Rented	1878	156	$	55.46	$	57.77
	757	Halide	Yard Lights - Rented	4346	362	$	95.91	$	101.25
	759	Halide	St Lights - Owned	533	44	$	8.95	$	9.59
	760	Halide	St Lights - Owned	894	74	$	15.01	$	16.10
	761	Halide	St Lights - Owned	1148	95	$	19.27	$	20.68
	762	Halide	St Lights - Owned	1878	156	$	31.50	$	33.81
	764	LED	St Lights - Owned	410	34	$	6.87	$	7.37
	765	Halide	St Lights - Owned	759	63	$	12.73	$	13.65
	766	LED	St Lights - Owned	295	25	$	4.95	$	5.31
	775	LED	St Lights - Owned	438	37	$	7.35	$	7.89
	780	LED	St Lights - Owned	586	49	$	9.83	$	10.55
	785	LED	St Lights - Owned	718	60	$	12.02	$	12.90

* These charges are applicable to existing fixtures only.

Maritime Electric Company, Limited
Schedule of Rates

		March 1, 2025	March 1, 2026
610	Pole Rental -Wood	$ 4.38	$ 4.38
	Residential		
	Unmetered Rates (based on 100 watt fixture)		
810	8 Hour Lighting per kWh	$ 0.2065	$ 0.2212
	Minimum Charge	$ 11.67	$ 11.67
820	12 Hour Lighting per kWh	$ 0.2065	$ 0.2212
	Minimum Charge	$ 11.67	$ 11.67
830	24 Hour Lighting per kWh	$ 0.2065	$ 0.2212
	Minimum Charge	$ 11.67	$ 11.67
840	Air Raid & Fire Sirens		
850	Outdoor Christmas Lighting - 5.77¢ per watt of connected load per week		
234	Customer Owned Outdoor Recreational Lighting		
	Service Charge	$ 24.57	$ 24.57
	Energy Charge per kWh for first 5,000 kWh	$ 0.2065	$ 0.2212
	Energy Charge per kWh for balance of kWh	$ 0.1270	$ 0.1417
	Short Term Unmetered Rates	Currently no customers in this rate category	
	Energy Charge:		
	per kWh of estimated consumption	$ 0.2065	$ 0.2212

Connection Charge:	Single-Phase	Three-Phase
A. Connecting to existing secondary voltage	$99.08	$99.08

B. Where transformer installations are required, the following connection charges will apply:

	Single-Phase	Three-Phase
(1) Up to and including 10 kVA	$148.87	$209.17
(2) 11 kVA to 15 kVA	$240.79	$301.01
(3) 16 kVA to 25 kVA	$269.20	$336.64
(4) 26 kVA to 37 kVA	$301.01	$336.64
(5) 38 kVA to 50 kVA	$336.64	$336.64
(6) 51 kVA to 75 kVA	$369.58	$523.96
(7) 76 kVA to 125 kVA	$431.07	$555.59
(8) Above 125 kVA	0	$594.94