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MARITIME ELECTRIC
A FORTIS COMPANY

October 23, 2026



Ms. Cheryl Bradley
Island Regulatory and Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Ms. Bradley:

2026 Capital Budget Application (UE20746)
Response to Additional Interrogatories from Commission Staff

Please find attached the Company's response to additional Interrogatories from Commission Staff with respect to the 2026 Capital Budget Application filed on November 4, 2025. An electronic copy will follow shortly.

Yours truly,

MARITIME ELECTRIC

Michelle Francis
Vice President, Finance &
Chief Financial Officer

MF45
Attachments

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ADDITIONAL INTERROGATORIES FROM COMMISSION STAFF

2026 Capital Budget Application
UE20746

filed October 23, 2026

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AFFIDAVIT

CANADA

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of Section 17(1) 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 of the Commission approving the 2026 Capital Budget and for certain approvals incidental to such an order.

AFFIDAVIT

I, T. Michelle Francis, of Emyvale, in Queens County, Province of Prince Edward Island, MAKE OATH AND SAY AS FOLLOWS:

1. I am the Vice President, Finance and Chief Financial Officer for Maritime Electric Company, Limited and as such have personal knowledge of the matters deposed to herein, except where noted, in which case I rely upon the information of others and in which case I verily believe such information to be true.

2. I prepared or supervised the preparation of the attached Interrogatory responses and to the best of my knowledge and belief the responses are true in substance and in fact.

SWORN TO at Charlottetown,
Prince Edward Island, the 23rd
day of October, 2026.

A Commission for taking affidavits in the
Supreme Court of Prince Edward Island

T. Michelle Francis

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INTERROGATORIES

The Island Regulatory and Appeals Commission (the "Commission"), in assessing the reasonableness of the 2026 Capital Budget Application (the "Application") submitted by Maritime Electric Company, Limited ("Maritime Electric" or "MECL"), requests responses to the following interrogatories:

IR-54 Section 3.3 - Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

a. This section states that the effects of this budget are expected to be offset through sales growth and operational efficiencies until the next GRA is in place.

   i. Can you please elaborate on the expected sales growth - how much growth is expected? What is expected to drive this growth? How much growth is required to offset the current capital budget as assumed?
   ii. What is meant by operational efficiencies? What projects in this budget are expected to improve this?

b. This section states that "approval of the Application as filed will not require any customer rate increase until the next GRA is filed" – once the GRA is filed, what is the expected effect of this capital budget on customer rates?

Responses:

a. i. Based on most recent load forecast, 2026 sales of approximately 1,626,000 megawatt hours ("MWh") is projected compared to a forecast of 1,431,000 MWh for 2025 in the General Rate Application ("GRA") resulting in a MWh sales increase of approximately 14 per cent.[1]

2026 energy sales growth is predominantly driven by increased residential space heating load as a result of the continued electrification of existing space heating due to heat pump replacement programs and housing starts, which are predominantly installing electric heating sources. In addition, the energy sales forecast for 2026 reflects an actual increase in residential sales attributable to the higher-than-normal heating degree days ("HDD") during the month of January 2026.[2] The forecast assumes a return to normal annual HDD for the remainder of the year.[3]

The incremental revenue associated with the projected sales increase will offset energy purchases and related operational expenses required to meet customer needs due to the growth in sales. However, it is estimated there will be sufficient margin available to offset the annual increase in revenue requirement resulting

[1] (1,626,000 MWh sales - 2026 forecast / 1,431,000 MWh sales – GRA 2025 forecast = 13.6 per cent).
[2] A heating degree day is a measurement designed to quantify the demand for energy needed to heat a building. It is the number of degrees that a day's average temperature is below 18 degrees Celsius, which is the temperature below which buildings need to be heated.
[3] The load forecast was prepared in February 2026 and, therefore, assumes normal HDD for the remainder of the year.

from the 2026 Capital Budget Application ("Application") as compared to the 2025 forecast previously projected in the GRA and currently included in approved rates.[4]

ii. The context of this information was not to imply that 2026 Capital Budget projects in and of themselves would lower operating costs in 2026. It was a more general comment that the Company's existing approved rates were approved by the Commission in UE23-04 and are based on 2025 revenue requirement. As the Company has elected to operate in 2026 outside of a GRA period, it has forecast one-time reductions in line maintenance and vegetation management spending to offset the inflationary cost increases not covered by the continued collection of 2025 customer rates in 2026.

b. As set out in Appendix E, "Estimated Impact on Rate Base, Revenue Requirement and Customer Rates," of the Application, the estimated impact at the time of filing was an increase of approximately 3 per cent relative to the customer rates then in effect. The next GRA, in which Maritime Electric would seek Commission approval to establish updated customer rates, has not yet been filed. Accordingly, the impact of the Application on customer rates cannot be updated or determined at this time.

[4] Estimated increase in revenue requirement in Appendix E of the Application reflects a full year. The 2026 increase in revenue requirement is approximately half of the full year revenue requirement due to half year rule for depreciation and averaging of the beginning and end of year rate base for the year will reduce return on debt, equity and tax by a half.

IR-55 Section 3.2 - Table 1: Proposed 2026 Capital Budget Expenditures

a. There is a projected customer contribution of $4,546,000, Can you please provide a further break down of this number? Please ensure, if this contribution is using budgeted contributions from 2021 through 2025, to include the actual contributions for the same period.

b. The total capital expenditures proposed in this budget does not include the Advanced Metering for Sustainable Electrification project, which has already been approved. To get a clearer picture of the total capital expenditures planned for the year, can you please send us an additional version of Table 1: Proposed 2026 Capital Expenditures that does include this project?

Responses:

a. The customer contribution breakdown for the Application is shown in Table IR-55(a)(i):

TABLE IR-55(a)(i)
Customer Contributions – 2026 Capital Budget Application

Description	Total
Regular Customer Contributions (see Note 1)	$ 1,846,000
Natural Resources Canada ("NRCan") (see Note 2)	900,000
Rural Broadband Make-Ready Contributions (see Note 3)	1,800,000
TOTAL	**$ 4,546,000**

Note 1: Table IR-55(a)(ii) is a calculation of the 2026 regular customer contributions budget, as filed in the Application.

TABLE IR-55(a)(ii)
Customer Contributions – 2026 Capital Budget Application

Description	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget
Contributions [5] (A)	$ 1,384,133	$ 1,346,601	$ 1,585,856	$ 2,979,763	$ 1,179,000
Escalation Rate [6] (B)	115.93%	112.55%	109.27%	106.09%	103.00%
Escalated to 2026 dollars (C = A X B)	1,604,590	1,515,611	1,732,908	3,161,231	1,214,370
2026 Contributions Budget – Average of 2021 to 2025 [7]					**$ 1,845,742**
2026 Contributions Budget (Rounded)					**$1,846,000**

[5] All amounts reflect actual contributions received, except the 2025 Capital Budget, which was calculated using the prior year's budget and actual contributions for the preceding four years, escalated to 2025 dollars.
[6] Escalation rates reflect the application of a 3 per cent annual escalation rate, compounded annually to 2026 dollars.
[7] $1,604,590 + 1,515,611 + 1,732,908 + 3,161,231 + 1,214,370 = $9,228,710 / 5 years = $1,845,742

Table IR-55(a)(iii) shows a calculation of the 2026 regular customer contributions budget using 2025 actual regular customer contributions received.

TABLE IR-55(a)(iii) **Customer Contributions – Based on Actual 2025 Results**					
Description	**2021 Actual**	**2022 Actual**	**2023 Actual**	**2024 Actual**	**2025 Actual**
Contributions[8] (A)	$1,384,133	$1,346,601	$1,585,856	$2,979,763	$1,952,585
Escalation Rate[9] (B)	115.93%	112.55%	109.27%	106.09%	103.00%
Escalated to 2026 dollars (C = A X B)	1,604,590	1,515,611	1,732,908	3,161,231	2,011,163
2026 Contributions Budget – Average of 2021 to 2025 [10]					**$2,005,101**
2026 Contributions Budget (Rounded)					**$2,005,000**

Note 2: The NRCan contribution relates to Table 56 of the Application. This is the second year of the Charlottetown Grid Modernization project, which was fully described in the 2025 Capital Budget Application. The contribution is calculated as 50 per cent of eligible project costs, in accordance with the NRCan Contribution Agreement, less a 10 per cent holdback. The project is estimated to incur costs of $2,000,000 in 2026, which would result in a contribution of $900,000.[11]

Note 3: Rural Broadband Make-Ready Project contributions are based on the Company's estimates for 2026 project activity. The project is described in Appendix K of the Application.

b. Appendix A to the Application sets out Maritime Electric's proposed 2026 capital expenditures and identifies capital projects previously approved by the Commission. The Advanced Metering for Sustainable Electrification project is included in the 2026 capital expenditures presented in Appendix A. In response to this interrogatory, Maritime Electric has prepared Table 1 - Amended that presents the total capital expenditures planned for 2026, including the Advanced Metering for Sustainable Electrification project previously approved by the Commission.

8 All amounts reflect actual contributions received.
9 Escalation rates reflect the application of a 3 per cent annual escalation rate, compounded annually to 2026 dollars.
10 $1,604,590 + 1,515,611 + 1,732,908 + 3,161,231 + 2,011,163 = $10,025,503 / 5 years = $2,005,101
11 $2,000,000 x 50 per cent = $1,000,000 less 10 per cent holdback = $900,000

TABLE 1 - AMENDED Proposed 2026 Capital Expenditures			
4.0	**Generation**		
	4.1	Charlottetown Generating Station – Buildings and Site Services	$ 630,000
	4.2	Charlottetown Generating Station – Turbine Generator	597,000
	4.3	Borden-Carleton Generating Station – Buildings and Site Services	82,000
	4.4	Borden-Carleton Generating Station – Turbine Generators	3,615,000
			4,924,000
5.0	**Distribution**		
	5.1	Replacements Due to Storms, Collisions, Fire and Road Alterations	2,425,000
	5.2	Distribution Transformers	12,039,000
	5.3	Services and Street Lighting	10,286,000
	5.4	Line Extensions	9,525,000
	5.5	Line Rebuilds	11,326,000
	5.6	System Meters [a]	8,173,000
	5.7	Distribution Equipment	6,763,000
	5.8	Transportation Equipment	3,617,000
			64,154,000
6.0	**Transmission**		
	6.1	Substation Projects	28,460,000
	6.2	Transmission Projects	9,765,000
			38,225,000
7.0	**Corporate**		
	7.1	Corporate Services	973,000
	7.2	Information Technology [b]	10,650,000
			11,623,000
Sub-total			$ 118,926,000
8.0	**Capitalized General Expense**		863,000
9.0	**Interest During Construction [c]**		2,905,000
Less:	Customer Contributions [d,e]		(17,356,000)
TOTAL			**$ 105,338,000**

a. 2026 System Meters total includes $6,873,000 for the AMI component of the Advanced Metering for Sustainable Electrification project.
b. 2026 Information Technology total includes $7,155,000 for the CIS component of the Advanced Metering for Sustainable Electrification project.
c. 2026 Interest During Construction total includes $1,478,000 for the Advanced Metering for Sustainable Electrification project.
d. 2026 Contributions total includes $12,810,000 for the Advanced Metering for Sustainable Electrification project.
e. Five-year average, calculated from actual and budgeted contributions from 2021 to 2025, normalized to 2026 dollars using an annual escalation rate of 3 per cent, plus estimated NRCan and Xplore contributions.

IR-56 Section 4.1(c) - Fuel Offloading Weather Enclosure

a. What is the approximate operating cost of maintaining the area through the winter without the enclosure?

b. Would this enclosure have any use after the planned decommissioning of the turbine?

Responses:

a. Snow clearing around the fuel offloading equipment is performed by Maritime Electric employees as required. The 2025 winter season saw 99 fuel trucks offload fuel, with most deliveries occurring in late fall and winter. The Company does not have historical records of time spent clearing snow around the fuel offloading equipment at the Charlottetown Generating Station ("CGS"), however, a reasonable estimate of the annual cost is approximately $1,000.

Regarding other maintenance, it is estimated that two Maritime Electric employees spend at least three days per year on fuel offloading equipment basic maintenance, at a cost of approximately $3,000. While annual maintenance will still be required with the proposed weather enclosure in place, it is expected that there will be some reduction in annual maintenance requirements.

b. With an expected lifespan of 60 years for combustion turbine #3 ("CT3"), it will be decommissioned in 2065. This lifespan is based on Maritime Electric experience with the two combustion turbines at the Borden Generating Station. If there is no other power generation equipment at the CGS that requires diesel fuel upon the decommissioning of CT3, the enclosure would no longer be needed for housing fuel offloading equipment and could be repurposed for some other use, if required.

If the On-Island Capacity for Security of Supply Project filing is approved,[12] the two additional combustion turbines proposed for the CGS would extend the need for fuel deliveries to the site and benefit from the fuel forwarding equipment being protected from the weather. Combustion turbines commissioned in 2029 would be expected to be in-service until 2089.

[12] Docket UE20742

IR-57 Section 4.1(d) - SCADA Video Wall Display

a. One of the future projects listed for 2027 includes adding GIS capabilities to SCADA. Is the current display upgrade necessary for this future project?

Responses:

a. No, the proposed display upgrade is not necessary for the future GIS capabilities to SCADA project, which is primarily a software-based upgrade.

IR-58 Section 4 – Generation

a. The intro to this section justifies these projects based on reliability and safety requirements as specified in the Electric Power Act, the Company's Energy Purchase Agreement ("EPA") with NB Power, health and safety legislation, insurance requirements and contingency plans. Can you please specify what these requirements are and how they are measured?

Responses:

a. Reliability and safety requirements that apply to Section 4.0 of the Application include:

Electric Power Act

Requirements
Reliability and safety are referenced in the *Electric Power Act*, Section 3. Duties of Public Utilities, which states:

> Every public utility shall
>
> (a) furnish at all times such reasonably safe and adequate service and facilities for services as changing conditions require;

In addition, the importance of safety requirements are also referenced in the *Electric Power Act*, Section 38. Public Safety, Commission May Make Orders to Protect, which states:

> If it is made to appear to the Commission that because of the faulty construction of the plant or lines of any public utility or other person, or the faulty installation of the equipment of the public utility or other person, or because of the neglect of any public utility or other person to maintain or repair its or his plant, lines or equipment, life or property is or may become endangered, the Commission may order such action to be taken with respect to the plant, lines or equipment of the public utility or other person as it may consider necessary for the public safety.

Measures
Reliability statistics of the Company's combustion turbines ("CT") are measured by the CT's key performance indicators ("KPI") which are documented monthly. These KPIs include the starting reliability percentage, the generator availability percentage, the forced outage percentage, and the planned maintenance outage percentage. In addition, monthly test runs of the CTs are performed.

Safety statistics for the CT operations are measured internally by the Company's Health, Safety and Environment ("HSE") department. Compliance with these safety requirements is measured through activities and indicators such as hazard assessments, inspections, audits, corrective action tracking, training completion, incident and near-miss reporting and investigating, safety meetings, incident prevention plans, emergency response

exercises, and both leading and lagging safety performance indicators. All of which are outlined within the Company's Health and Safety Management System.

Additional reliability and safety items are measured by Maritime Electric employees, contractors, and original equipment manufacturers ("OEM"). These include the annual maintenance outages, power turbine borescope inspections, fire suppression system inspections and tests, and more. All safety items are addressed in a timely manner, as required.

Energy Purchase Agreement ("EPA") with NB Power

Requirements
Reliability requirements are referenced in the EPA with NB Power in Section 2.4 Capacity Based Ancillary Services and Section 4.1 Nature of Services.

Section 2.4 - Capacity Based Ancillary Services indicates that Maritime Electric is responsible to provide ancillary services to NB Power from the Company's capacity resources, including 10-minute non-spinning supplemental reserve and 30-minute non-spinning supplemental reserve.

Section 4.1 - Nature of Service indicates that secure energy and assured energy are energy products available to Maritime Electric that may be curtailed or interrupted by NB Power. These energy products are intended to minimize the operation of Maritime Electric's on-Island dispatchable generation resources provided that they are available as backup resources.

Measures
The EPA attributes each Maritime Electric generating unit a purpose. The purposes include for the unit to act as a capacity-based ancillary service or for secure and assured energy purchases. As such, it is imperative that the Company's generating units are operated reliably and safely to minimize the forced outage rate. Projects identified in Section 4 are required to keep these units operating reliably.

In addition to the previously mentioned CT KPIs and reliability actions performed, the Company evaluates several factors, such as information from its' insurers, improvements in safety systems from OEM contractors, information from HSE legislation, and information from NB Power to maintain these units and to identify potential issues that could cause a forced outage.

Health and Safety Legislation

Requirements
Health and safety requirements applicable to Section 4 projects include following the PEI Occupational Health and Safety Act, the Occupational Health and Safety Act General Regulations, Canadian Standards Association codes, Canadian Electrical Code, American Petroleum Institute standards, National Fire Protection Association standards, American Society of Mechanical Engineers codes, applicable Federal and Provincial environmental legislation, and more.

Maritime Electric follows an internal policy called the Standard Protection Code for working safely on and around electrical equipment and facilities. The Company also follows good utility practice for operations.

Measures
Safety statistics for the CT operations are measured internally by the Company's HSE department. Compliance with these safety requirements is measured through activities and indicators as previously mentioned.

Additional reliability and safety items are measured by Maritime Electric employees, contractors, and OEMs, also, as previously mentioned.

Insurance Requirements

Requirements
Insurance due diligence for reliability and safety encompass meeting all current and new insurance requirements resulting from notifications, inspections, and audits. These can include directions to make upgrades to equipment to ensure system protection and safety, the addition of new equipment, testing of critical systems, and to implement new good utility practice measures.

Measures
These insurance requirements are measured through audit validations and test results, in addition to the previously mentioned reliability and safety items measures.

Contingency Plans

Requirements
Contingency readiness requirements as they relate to reliable CT operation are broadly specified in the *Electric Power Act* and the NB Power EPA, as stated previously.

Contingency readiness is also broadly referenced in internal Company documents, with the overarching source being the Business Contingency and Disaster Recovery Plan, which states:

> Maritime Electric operates under the provisions of the Prince Edward Island Electric Power Act, which states an obligation to serve. Consistent with this obligation, Maritime Electric must ensure that any interruption of service is minimized. This shall be accomplished by planning timely and appropriate responses to emergencies that result in the interruption of critical Company functions such as the supply and distribution of electricity, internal and external communications, and billing systems.

Measures
Contingency requirements are measured through CT KPIs and test runs, as previously mentioned. Critical systems have redundancies in place and are tested monthly.

IR-59 Section 4.2(b) - CT3 Water Treatment Equipment Replacement

a. This project is justified in the application based on the equipment being at the end of its service life. In your response to the Commission's previous interrogatories, you specified that the system will be 20 years old in 2026, with an expected service life of 10-20 years.

i. In your 2025 Capital Budget application, upgrades to the RO-EDI equipment were scheduled as a capital project for 2027. What changed between these two applications that required this project in 2026 rather than 2027?

Responses:

a. i. The project was advanced from 2027 to 2026 due to increased operation of the CT3 water treatment system (directly related to increased CT3 operation) and continued age-related degradation of the electrodeionization ("EDI") stacks, as noted in the response to IR-3.

Maritime Electric received information from the water treatment equipment supplier in November 2025 indicating that critical analyzers, transmitters, and associated sensing probes required for system operation had also become obsolete. The combination of increasing equipment degradation and the identification of components that cannot be replaced due to their unavailability, increased the risk to long-term system reliability and warranted advancing the project to 2026.

IR-60 Section 4.4 (d) - CT1 and CT2 Computer Hardware and Software Replacement

a. This project is justified in the application based on the current systems being obsolete. However, based on the software and controllers listed, it seems that some of them have been obsolete for some time already (ex. CT1's controller was installed in 2003, and a typical obsolescence of 15 years indicates that it would have been obsolete in 2018 based on the numbers given in your application). Can you please explain why you have determined these upgrades to be necessary in the current year and not in any of the preceding years when they were also obsolete?

b. We weren't able to find this project listed in the Future Capital Projects section of capital budget applications for previous years. Can you please indicate why this project wasn't identified by your capital spending processes sooner?

c. After using obsolete software for so many years already, would it be possible to continue using the existing system for the remaining operational life of the CT1 and CT2 turbines in the lead up to their decommissioning?

Responses:

a. Although portions of the combustion turbine #1 ("CT1") and combustion turbine #2 ("CT2") control systems became obsolete in prior years, operating the equipment using existing spare part inventories continued while balancing the cost of replacement against the associated reliability risk. As the equipment continues to age, the risk of failure increases and the availability of replacement parts in the marketplace declines.

It has been determined that the remaining inventory of spare components and the increasing risk associated with prolonged reliance on obsolete equipment now warrants replacement to maintain reliable operation of the units through to their planned retirement dates. However, where vintage replacement components can be sourced, and where their use can reduce the scope of consequential replacements and upgrades, this will be done if it is the least-cost option. Given Maritime Electric's capacity deficit, CT1 and CT2 are critical for security of supply, and their controls equipment must be properly maintained.

b. The project was not identified in previous Future Capital Project lists because Maritime Electric had sufficient spare components available to support continued operation of the existing control systems. As the equipment has continued to age and the availability of replacement parts has further diminished, the risk associated with maintaining the obsolete system has increased. Based on these changing conditions, the project was added to the current Future Capital Projects list to help ensure the reliable operation of CT1 and CT2 through to their retirement.

c. While it may be possible to continue using the existing system for the remaining operational life of CT1 and CT2, it is not recommended. The human machine interface ("HMI") system consists of both, hardware and software components that must remain reliable, compatible, and supportable throughout the life of the units. Aging hardware components within the HMI system, like desktop computers with mechanical hard drives, present increasing reliability risks as they continue to age. As hardware is replaced to

maintain reliability, the associated software must also be upgraded to remain compatible with the hardware's operating systems. Without these hardware and software upgrades, the ability to safely and reliably operate CT1 and CT2 will be increasingly compromised.

IR-61 Internal and External Labour:

a. The below table breaks down the budget categories for the 2026 and 2025 capital budgets before factoring in customer contributions. Based on below the Internal Labour decreased from 22% in 2025 to 17% in 2026; meanwhile, Contract Labour increased from 12% to 19% (i.e. it makes up a larger proportion of the total budget in 2026 than internal labour) and the "Other" category (including Civil works, other various services not listed explicitly as "Contract Labour") increased from 1% to 8%.

i. Can you please explain this increased emphasis on external labour?
ii. With budgeted contract labour increasing from $ 9.5 million to nearly $20 million, do you foresee any challenges in finding the labour to complete these services?

IRAC Table 1
Summary of Capital Budget Application by Category (before customer contributions)

Description	**2025**		**2026**	
Material	46,748,627	61%	55,218,000	52%
Internal Labour & Transportation	16,782,000	22%	17,900,000	17%
Contractor Labour	9,473,000	12%	19,924,000	19%
Contingency	1,301,373	2%	3,214,000	3%
Other	639,000	1%	8,642,000	8%
Capitalization of General Expense	919,000	1%	863,000	1%
Interest During Construction	869,000	1%	1,427,000	1%
Total Capital Budget (before customer contributions)	**$76,732,000**		**$107,188,0000**	

Responses:

a. i. Maritime Electric uses external (contracted) labour for capital projects where workloads fluctuate because external labour resources can be scaled up or down more readily than internal labour resources, as needed. Projects such as distribution line extensions and rebuilds, communications make-ready work, and transmission line construction are typically completed using external labour for the reasons set out in the response to IR-67(b)(ii).

The increased reliance on external labour relative to internal labour between the 2025 and 2026 capital budgets is attributable primarily to the combined effect of the budget items shown in Table IR-61 and discussed below.

Table IR-61 External Labour Budget Differential – 2025 and 2026			
Capital	**2025 Budget**	**2026 Budget**	**Budget Differential**
Budget Section/Item	(A)	(B)	(C = B - A)
5.2 Distribution Transformers	$ 54,000	$ 556,000	$ 502,000
5.3(a) Overhead and Underground Services	750,000	1,185,000	435,000
5.4(b) Load and Reliability Driven Line Ext.	1,036,000	5,518,000	4,482,000
5.5(a)(iv) Rural Broadband Make Ready	-	3,500,000	3,500,000
5.7(f) Charlottetown Grid Modernization	180,000	1,065,000	885,000
6.2(c) Transmission Lines	1,684,000	2,926,000	1,242,000
TOTAL	**$ 3,704,000**	**$ 14,750,000**	**$ 11,046,000[a]**

a. The external labour budget differential of $11,046,000 in Table IR-61 is higher than the contractor labour differential of $10,451,000 (= $19,924,000 - $9,473,000) in IRAC Table 1 because Table IR-61 includes only budget items with larger increases, rather than the resulting differential of all budget items (per IRAC Table 1) of which some had relatively smaller increases and some had decreases.

Section 5.2 – Distribution Transformers and Section 5.3(a) Overhead and Underground Services:

These projects are forecast with contractor labour cost increases of approximately $0.5 million and $0.4 million, respectively, in 2026. Both budget items are directly impacted by Provincial Government programs to incent heat pump installations, which has created more work and increased the need for contractor resources to supplement existing internal labour resources.

Section 5.4(b) – Load and Reliability Driven Line Extensions:

These projects are forecast with external labour increases of approximately $4.5 million in 2026. This budget item reflects an increase in the number and scale of projects required to address customer load growth across the distribution system, as detailed in the response to IR-66.

Section 5.5(a)(iv) – Rural Broadband Make-Ready:

This project is forecast with an external labour budget requirement of approximately $3.5 million. As 2026 is the first year that this project is included in an annual capital budget (it was reported as an over-budget variance in 2025), it represents approximately 33 percent of the external labour increase over the 2025 amount (i.e., $3,500,000 / $10,451,000 = 0.33).

Section 5.7(f) – Charlottetown Grid Modernization Project:

This project is forecast with an external labour budget requirement that is approximately $0.9 million higher than in 2025. The external labour for this project is associated with engineering services to complete studies and support procurement processes.

Section 6.2(c) – Transmission Lines:

Transmission line projects are forecast with an external labour budget requirement that is approximately $1.2 million higher than 2025. The increase is due to the net

differential in external labour budgeted for two multi-year projects with work occurring in both 2025 and 2026. The Y-106 Scotchfort to Lorne Valley external labour budget for 2026 is approximately $0.8 million less than 2025, while the Y-119 Extension to Scotchfort external labour budget for 2026 is approximately $2 million more than 2025. As such, net external labour is up by approximately $1.2 million for 2026.

ii. No, Maritime Electric does not anticipate any challenges in sourcing external labour to complete the planned work.

IR-62 Section 5.1(b) - Replacements due to Road Alterations

a. The application listed a provisional amount based on historical figures since the provincial infrastructure plans had not yet been released at the time the application was written. Now that this report has been released, do you anticipate any changes to this amount?

Responses:

a. Section 5.1(b) is currently estimated to be approximately $300,000 over budget for 2026. The over-budget variance estimate is due primarily to multiple complex projects, including the Kingston Road traffic circle, the Mill River traffic circle, and the Coleman Corner bridge replacement. As it is considered obligatory to support Provincial Government road alternations, Maritime Electric has already completed most of the work required for 2026.

IR-63 Section 5.2(a) - Distribution Transformers

a. The application indicates that the materials budget is down based on current inventories. Can you please indicate the approximate number of each transformer type in your inventory at the beginning of 2026? How many of these were purchased in 2025?

b. How many transformers of each type are expected to be installed in 2026?

c. With the Oil to Heat Pump Affordability (OHPA) Program closing to new applicants as of July 2026, does this have any impact on your forecasts for new transformers for the current budget?

Responses:

a. At the beginning of 2026, poletop transformer inventory was approximately 3,252 and padmount transformer inventory was approximately 362.

Of the transformers in inventory at the beginning of 2026, approximately 1,126, poletop transformers and 89 padmount transformers were purchased in 2025.

Maritime Electric manages transformer inventory in accordance with good utility practice by maintaining sufficient inventory to support forecast customer growth, planned capital projects, minimum stock objectives, and emergency response requirements. Inventory levels cannot be evaluated solely by comparing total units in stock to annual installation requirements because transformer inventories consist of many different voltage classes, kilovolt ampere (“kVA”) ratings, single-phase and three-phase configurations, and poletop and padmount designs. For example, inventory may be sufficient in one transformer size while simultaneously being below target levels in another size or voltage class, and inventory available in one category may not be suitable for a customer installation, system upgrade, or emergency replacement requiring a different specification. In addition, a portion of the inventory is maintained as emergency and contingency stock to support storm restoration, equipment failures, and supply-chain risk mitigation.

Maintaining adequate inventory levels is particularly important given the lead times associated with transformer procurement and the Company's obligation to provide timely customer connections and restore service following unplanned equipment failures. Accordingly, the Company's transformer forecast considers existing inventory balances by transformer category, target and minimum stock levels, forecast installations, historical and projected customer demand, planned capital work, equipment replacement requirements, and the need to maintain sufficient emergency reserves. Procurement decisions are based on these category-specific requirements rather than total inventory quantities alone.

b. Expected installations for 2026 are 2,009 for poletop transformers, and 104 for padmount transformers.

c. No. Maritime Electric was recently informed by the Office of Net Zero (which administers the OHPA program) that additional funding was received such that the estimated number of customers served by the OHPA program will be comparable to the previous year.

IR-64 Section 5.3(a) - Overhead and Underground Services a. With the Oil to Heat Pump Affordability (OHPA) Program closing to new applicants as of July 2026, does this have any impact on your forecasts for services for the current budget?

Responses:

No. For the same reason provided in response to IR-63(c), the forecast for services for the current budget has not changed.

IR-65 Section 5.3(b) - Street and Area Lighting

a. This program is described as covering the installation of LED pole-mounted street and yard lights, the replacement of HPS lanterns with LED lanterns, and light replacements due to fixtures reaching the end of their useful life. Can you please break down how much of this budget is for each of these activities?

b. How much longer would the HPS lanterns be expected to last if they weren't replaced in the current year?

c. The application mentions that the lanterns are rented – can you please elaborate on how this rental income is recorded? What is the amount of rental income earned from these lanterns in each of the past five years? Is rental income expected to increase after converting the lanterns to LED?

Responses:

a. Approximately 33 per cent of the 2026 budget for street and area lighting is associated with the HPS lantern replacements, with the remainder primarily associated with new street lights. As the vast majority of street lights were converted to LED within the past 12 years, replacements are typically only required when street lights are damaged beyond repair (e.g., as a result of a vehicle hitting a pole).

b. The Company cannot predict lantern failures; however, lantern replacements were included in the 2026 Application because failures are occurring due to age and damage by external forces. Due to the lack of replacement parts, repairs are not practical and any damaged or failed lanterns must be replaced.

Given the relatively small number of lanterns (relative to pole-mounted lights) and because they tend to be clustered by location (e.g., in municipal parks and historic areas), it is more practical and efficient to replace them through a program rather than replace lanterns individually, as they fail. The replacement LED lanterns are also much more energy efficient.

c. To clarify, the term "rented" simply implies that the lighting is owned by Maritime Electric, and not by the customer. Revenue for lanterns is recorded the same as all other street and area lighting. Regarding income following replacements, please refer to the response to IR-10.

IR-66 Section 5.4(b) - Load and Reliability Driven Line Extensions

a. The budget for this section is nearly 5 times greater than the adjusted average of the previous five years. Can you justify an increase of this magnitude given that the metrics you use to measure reliability performance (SAIDI and SAIFI) have remained relatively stable over the past decade (Section 3.5 System Reliability Performance and Improvement)?

Adapted from Table 34 Historical and Proposed Capital Expenditures Load and Reliability Driven Line Extensions						
Description	**2021**	**2022**	**2023**	**2024**	**2025 Budget**	**2026 Budget**
Material	$245,167	$188,315	$319,166	$236,149	$233,000	$1,323,000
Contractor Labour	310,700	629,606	1,470,845	707,416	1,036,000	5,518,000
Internal Labour and Transportation	270,000	306,852	316,268	196,051	214,000	424,000
Other	6,255	3,962	156,812	3,075	-	-
Less: Joint use Charged To/Owned by Third Party	-	-51,725	-	-	-	-
TOTAL	**$832,122**	**$1,077,010**	**$2,263,091**	**$1,142,691**	**$1,483,000**	**$7,265,000**

Responses:

a. The increase in the 2026 Load and Reliability Driven Line Extensions budget is primarily the result of a higher number of projects required to address customer load growth across the distribution system. The proposed projects are intended to relieve highly loaded feeders, provide voltage support, balance load across phases, accommodate increasing customer demand, and create alternative supply paths where practical. As such, they are not based on past reliability performance.

While these projects provide reliability benefits, their primary driver is load growth and the need to maintain acceptable power quality, equipment loading, and system operating conditions as customer demand increases. This is consistent with the Company's long-standing planning approach and with the project drivers identified in response to IR-11, where Section 5.4(b) projects were characterized primarily as load-growth driven.

IR-67 Section 5.5(a) - Single Phase and Three Phase Line Rebuilds

a. Table 36: Historical and Proposed Capital Expenditures Single Phase and Three Phase Line Rebuild includes the joint use charged to/owned by a third party for 2021 and 2022.

   i. Should the current year also include a third-party amount related to Xplore's contributions for the Rural Broadband project?
   ii For illustrative purposes, can you please send us an additional version of Table 36 that includes these contributions for 2026 (and previous years, as applicable)?

b. The portion of contractor labour included in this budget has increased from the 40%-50% range in previous years to over 70% in 2025 and 2026.

   i. Can you please explain the reasoning for this increase?
   ii. What would the impact be on the budget if a greater proportion of internal labour was used instead? Are there other reasons that this wouldn't be feasible?

c. The budget for this section is over 2 times greater than the adjusted average of the previous five years (before third-party contributions). The justification listed for this project is to provide safe and reliable service – same as above, can you justify this given that the metrics you use to measure reliability performance (SAIDI and SAIFI) have remained relatively stable over the past decade (Section 3.5 System Reliability Performance and Improvement)?

Responses:

a. i. No, Xplore's contributions for the Rural Broadband Make-Ready ("Rural Broadband") project are recorded to "Contributions" and not "Line Rebuilds". The estimated contribution amounts for the Rural Broadband project are included in Table 4 of Appendix K in the Application.

   ii. As the Xplore contributions do not belong in Table 36, it would be more appropriate to simply list the Rural Broadband project expenditures and contributions as shown in Table IR-67.

Table IR-67
Actual and Forecast Expenditures and Contributions
Rural Broadband

Year	Description	Expenditures	Contributions
2025 Actual	Xplore Rural Broadband	$ 1,926,686	$ 915,581
2026 Forecast	Xplore Rural Broadband	4,050,000	1,800,000
2027 Forecast	Xplore Rural Broadband	1,228,000	450,000
TOTAL		**$ 7,204,000**	**$ 3,165,581**

b. i. The increase in the portion of contractor labour for Section 5.5(a) is primarily associated with the Rural Broadband project. When the Rural Broadband project is removed, the portion of contractor labour for 2026 is 58 per cent, which is comparable to the 5-year average of 53 per cent.

ii. Maritime Electric does not have the resources to support the significant, but short-term, increase in resources required to execute a project like the Rural Broadband initiative. The Company's internal-labour model is scaled to meet normal customer demand, rather than scale up and down with variable, large-scale project requirements. If a greater portion of internal labour was used on the Rural Broadband project, the need for contractor labour would shift to other activities, as the internal labour resources assigned to Rural Broadband would need to be replaced within some other budget item.

c. The increase in budget is primarily associated with the Rural Broadband project. When the Rural Broadband project is removed the remaining budget is $2,292,000, which is below the five-year average.

IR-68 Section 5.5(d) - Distribution Corridor Widening

a. The application states that once a corridor is widened under this program, it will be maintained under the vegetation management program (operational expense).

   i. How many kilometres of distribution and transmission lines are currently being maintained under this program?
   ii. Does this maintenance program include sections along private property?
   iii. Once a private landowner gives permission for corridor widening, is this section automatically included in the maintenance program, or are there any additional permissions that must be obtained?

b. Can you please give some additional details as to how landowner permission is obtained for this program:

   i. The response to IRAC's previous queries indicated that segments of distribution line were identified for this program in a 2025 satellite scan of the full system. For the segments identified in this scan, were permission requests sent out all at once, or were they only sent out for each year for the sections expected to be completed during that year?
   ii. At the end of 2025, were there any properties where permission was obtained, but widening had not yet taken place?
   iii. For the previous year of this program (2024 and 2025) can you please indicate how many permission requests were sent out, and what portion of those requests were positive?

Responses:

a. Please note that the vegetation management program includes both capital and operating expenditures. As per standard utility practice, corridor widening and corridors established for new lines are capital expenditures, whereas maintenance trimming of existing corridors (including corridors that have been widened) are operating expenditures.

   i. Through corridor widening completed in 2024 and 2025, a total of 194 kilometres ("km") of distribution lines and 41 km of transmission lines have been widened and will be maintained under the vegetation management program as an operating expense. These corridors are now subject to maintenance activities as required to preserve the clearances established through the widening program.

   ii. Yes, Maritime Electric's vegetation management program includes work on private property where vegetation encroaches on required electrical clearances and where the Company has either the legal right to perform the work through an easement or has obtained the necessary landowner permission.

   iii. Permissions previously granted for widening do not entitle Maritime Electric to perform subsequent work on private land. Therefore, in the absence of an existing easement, the Company's approach is to request permission each time that maintenance is required on private land.

b. i. To clarify, the Satellite-Based Vegetation Imaging program provides insight into priority areas for vegetation management and not specifically widening. The opportunity to widen existing corridors is based on field review, planning, related distribution line work, and customer consultation. Therefore, permissions are requested on a case-by-case basis where widening is determined to be viable and beneficial.

ii. Yes. At the end of 2025, there were properties where permission had been obtained but corridor widening had not yet taken place. Corridor widening work is planned and executed based on annual priorities, available resources, project coordination opportunities, and landowner permissions. As a result, some properties for which permission had been obtained remained on the approved work list awaiting crew dispatch for completion. Obtaining permission does not necessarily result in immediate corridor widening, as work is scheduled based on operational priorities and program execution requirements.

iii. In 2024, Maritime Electric issued 77 landowner permission requests, of which 78 per cent resulted in positive responses. The remaining requests were either declined or did not receive approval.

iv. In 2025, Maritime Electric issued 165 landowner permission requests, of which 58 per cent resulted in positive responses. The remaining requests were either declined or did not receive approval.

IR-69 Section 5.5(e) - Satellite-Based Vegetation Imaging

a. This program is described as a recurring analysis to support vegetation management. As mentioned previously in the application, the vegetation management program is an operational expense. Additionally, only 20% of the distribution system will be analyzed in 2026 and each year going forward. Can you please justify why this should be a capital item and not an operational expense?

Responses:

a. The Satellite-Based Vegetation Imaging program is distinct from the physical vegetation management activities that it supports. Physical vegetation management within existing corridors, including routine cutting, trimming, and maintenance, is recorded as an operating expense. The expenditure included in Section 5.5(e), however, is primarily for the acquisition and processing of satellite imagery and the related analysis that creates and periodically renews a long-term vegetation condition and risk dataset for Maritime Electric's distribution system.

The annual analysis of approximately 20 per cent of the system does not represent a one-year operating service. Rather, it establishes a five-year refresh cycle under which imagery and analysis for each portion of the system have a useful life extending beyond the year in which they are acquired. On that basis, the imagery acquisition, data processing and risk analysis costs are capitalized and amortized over approximately 10 years,[13] while recurring software maintenance, licensing, and support costs are expensed annually. This treatment is consistent with the capitalization rationale previously provided to the Commission for this program.

Although approximately 20 per cent of the system is refreshed each year, the analysis is cumulative and forward-looking. The 2025 full-system scan established the baseline, and subsequent annual scans update portions of that asset while also informing vegetation management priorities one to two years in advance and identifying areas that should be included in future scans. Vegetation conditions, growth rates, distribution facilities, and customer connectivity change over time; therefore, the recurring scans maintain the relevance of the system-wide dataset and improve the associated growth and risk models.

Accordingly, the capital expenditure is not the cost of performing routine vegetation maintenance. It is the cost of acquiring imagery and producing corrected geospatial, vegetation-condition and risk-analysis information that provides benefits over multiple accounting periods and supports future planning, work prioritization and reliability decisions. The subsequent vegetation management work identified through the analysis continues to be charged to the appropriate operating or capital vegetation management program based on the nature of that work. Annual software licensing, maintenance and support costs that do not create or renew the underlying data asset are recorded as operating expenses.

[13] Capitalized costs are amortized with computer software under the current depreciation study.

IR-70 Section 5.6(a) - Residential and Apartment Meters

a. This section includes a "customer-growth true-up of 1,337 additional AMI meters to capture approximately 25 percent of new meter requirements from 2023 to 2025 that were not included in the AMI project budget."

i. Can you please clarify this section? Does this mean these were non-AMI meters that were installed in 2023-2025 that are now being replaced with AMI meters?
ii. What is the $ amount for this true-up?

Responses:

a. i. The number of meters included in the Advanced Metering for Sustainable Electrification project application was based on the customer count as of December 31, 2023. The proposed true up reflects the projected need at the end of the Advanced Metering for Sustainable Electrification project considering: (i) actual customer growth to the end of 2025; (ii) an estimated additional 2,000 meters in each of 2026 and 2027 to address customer growth and reserve stock necessary to service any faulty or damaged meters for 2028; and (iii) a net reduction due to net metering customers requiring only one AMI meter to service their net metering needs on the new system. Table IR-70(a)(i) below shows this reconciliation.

TABLE IR-70(a)(i)
Meter Requirements – 2027 Forecast

Meter Type	Customer Count 12/31/2023 (A)	Customer Count 12/31/2025 (B)	Net Metering Reduction (C)	Variance (D = B + C – A)	2026 Customer Growth [14] (E)	2027 Customer Growth [I] (F)	Meters to Purchase (G = D + E + F)
Residential	74,964	83,034	(4,000)	4,070	1,450	1,450	6,970
Apartment	4,188	4,900	-	712	450	450	1,612
Commercial	3,563	4,264	-	701	100	100	901
TOTAL	**82,715**	**92,198**	**(4,000)**	**5,483**	**2,000**	**2,000**	**9,483**

Also referring to Table IR-70(a)(i), the projected total meter requirement to address the actual customer count to December 31, 2025 is 5,483 meters, as shown in column D, of which 4,782 is the residential/apartment meters requirement. There is also a projected growth and inventory need for an additional 2,000 meters in each of 2026 and 2027. As such, 8,582 residential/apartment meters are required by the end of 2027.

Maritime Electric has applied for a 2025 metering budget carryover of $400,000 which will be used to purchase approximately 2,016 meters of which 1,908 are

[14] Estimated additional need for new customer growth and reserve stock for damaged and faulty meter replacement needs.

residential/apartment meters. Based on 8,582 residential/apartment meters being required by end of 2027 and with 1,908 of this requirement to be purchased using 2025 budget carryover funds, the total number of residential/apartment meters needed in 2026 and 2027 is 6,674, or approximately 3,337 per year.

ii. The estimated total cost of the true-up meters (i.e., residential/apartment and commercial/industrial) over the three-year period is approximately $2 million.[15] The Company's plan to meet the true-up meter needs, as calculated in Table IR-70(a)(i), includes the carryover of an unused 2025 Capital Budget metering budget to purchase 2,016 meters,[16] with the remaining required meters to be split equally and budgeted within the 2026 and 2027 capital budget applications as shown in Table IR-70(a)(ii).

As shown in Table 47 of the Application, the Company projects meter costs (material column) to address residential/apartment and commercial/industrial needs of $647,000 and $139,000, respectively, which agrees to the 2026 meter cost budgeted in column F of Table IR-70(a)(ii) below.

TABLE IR-70(a)(ii)
Meter Requirements – 2027 Forecast

Meter Type	Meters to Purchase (A)	Price per meter (B)	2025 Carryover Units (C)	2025 Carryover Costs (D = B X C)	2026 Budget Units (E)	2026 Budget Costs (F = B X E)	2027 Budget Units (G)	2027 Budget Costs (H = B + 3% X G)	Total Meter True Up Costs (I = D + F + H)
Residential	6,970	179.68	1,636	$ 293,956	2,667	$ 479,207	2,667	$ 493,583	$ 1,266,746
Apartment	1,612	250.29	272	68,079	670	167,694	670	172,725	408,498
Commercial	901	351.31	108	37,941	397	139,470	396	143,292	320,703
TOTAL	**9,483**		**2,016**	**$ 399,976**	**3,734**	**$ 786,371**	**3,733**	**$ 809,600**	**$ 1,995,947**

[15] Total additional meter cost = Table IR-70(a)(ii), $399,976 (column D) + $786,371 (column F) + $809,600 (column H) = $1,995,947

[16] Maritime Electric addressed the need for additional AMI meters within the 2025 Capital Budget Variance Report – Docket UE20747, as filed February 25, 2026.

IR-71 Section 5.6(b) - Commercial and Industrial AMI Meters

a. Can you please indicate, in the proportion of the budget from this section, that are due to forecast customer growth vs. replacing existing meters?

b. What factors do you consider in your customer growth forecasts?

Responses:

a. Referring to Table IR-70(a)(i), the projected total meter requirement to address the actual customer count to December 31, 2025, is 5,483 meters, as shown in column D, of which 701 is the commercial/industrial meters requirement. There is also a projected growth and inventory need for an additional 100 meters in each of 2026 and 2027. As such, 901 commercial/industrial meters are required by the end of 2027.

As noted in the response to IR-70, Maritime Electric has applied for a 2025 metering budget carryover of $400,000 which will be used to purchase approximately 2,016 meters of which 108 are commercial/industrial meters. Based on 901 commercial/industrial meters being required by end of 2027 and with 109 of this requirement to be purchased using 2025 budget carryover funds, the total number of commercial/industrial meters needed in 2026 and 2027 is 792, or approximately 396 per year.

b. Modest total customer growth was determined based on evaluating the average customer count increase from 2023 to 2025 considering a 4,000 meter reduction from net-metering customers on the new system.[17] While an average of 2,742 new customers were added to the system in the years 2024 and 2025, 2,000 is believed to be a reasonable estimate for customer growth and reserve stock needs to address any damaged or faulty meters in each of 2026 and 2027.

[17] Average annual increase in customer base of 2,742 = (92,198 – 82,715 – 4,000) / 2 years.

IR-72 Section 5.7(a) - Substation, Line, and Communication Equipment

a. The application mentions that the need for reclosers in 2026 is determined based on loading data from winter 2025. Can you please elaborate on this process? Is there a quantifiable threshold used to determine which feeders need reclosers?

Responses:

a. Section 5.7(a) is a recurring budget category for the upgrade or replacement of existing substation, line and communication equipment based on condition, age, test results and operating history. As clarified in IR-18, this statement that the 2026 requirements are determined based on loading data from winter 2025 pertains to Section 5.7(g), High Load Readiness Equipment, and was inadvertently included in Section 5.7(a).

For the high-load readiness project, 5.7(g), the winter peak loading for each feeder is reviewed after the winter season to identify feeders experiencing significant load growth or operational stress. Feeders are prioritized based on peak loading, restoration requirements, feeder configuration, the number and location of customers, and the ability to sectionalize the feeder during an outage. During restoration, cold-load pickup can increase feeder loading by as much as 200 per cent. Reclosers allow the feeder to be divided into smaller sections so that load can be restored in stages and within equipment operating limits.

There is not a single system-wide loading threshold that automatically determines whether a recloser is required. The decision is based on an engineering review of the feeder-specific conditions noted above, with priority given to heavily loaded feeders where additional sectionalizing will provide the greatest operational and reliability benefit. Winter 2025 loading data is analyzed together with these factors to confirm the location and timing of proposed installations.

IR-73 Section 5.7(b) - Relay Replacement Equipment

a. The application indicates that all electromechanical relays are being updated to microprocessor ones for "cost efficiency": can you please estimate the effect of this change on operating expenses?

b. What is the remaining lifetime of the current processors if they weren't updated immediately?

Responses:

a. The Company has not separately quantified a reduction in operating expenses from replacing electromechanical relays with microprocessor-based relays. The cost-efficiency reference relates primarily to lifecycle, maintenance and operational benefits. Many electromechanical relays are discontinued, with replacement parts and technical support increasingly difficult to obtain. They are also more susceptible to environmental conditions and require field personnel to manually verify operating and tripping thresholds, typically on a three- to six-year cycle. Microprocessor-based relays can consolidate multiple protection functions and provide automated self-monitoring, event recording and communications. These capabilities reduce discrete equipment, wiring and panel-space requirements, support remote condition and compliance reporting, improve system visibility, and make testing, troubleshooting and future modifications more efficient. Any operating-expense savings would occur over the equipment lifecycle and, as such, are not included as a specific reduction in the 2026 operating budget.

b. Table IR-73 show the ages and planned replacement schedule for each of the five remaining electromechanical relays. These relays will remain in service in accordance with this schedule provided they continue to perform reliably. Earlier replacement may be required if a relay fails, replacement parts or technical support become unavailable, or system protection, control or communication requirements change.

Table IR-73
Remaining Electromechanical Relays Replacement Schedule

Relay Location	Year Installed	Replacement Year
Sherbrooke Substation 138 kV Bus	2008	2026
West Royalty X1 Distribution Transformer	1972	2028
West Royalty X4 Distribution Transformer	1976	2028
West Royalty X2 Distribution Transformer	1994	to be determined
West Royalty X3 Distribution Transformer	2002	to be determined

IR-74 Section 5.7(c) - Switch Replacement Equipment

a. The switch inspection program mentioned here – is it included in the capital budget, or is it an operational expense?

Responses:

a. The switch inspection program referenced in Section 5.7(c) is included in the capital budget.

IR-75 Section 5.7(g) - High Load Readiness Equipment

a. This section and 5.7(a) Substation, Line, and Communication Equipment both budget for reclosers and capacitor banks to support load growth. Please explain how equipment is differentiated between these two budgets.

b. Should we expect to see any decrease in the other capital budget areas for distribution equipment as a result of this project?

Responses:

a. There is no duplication between Sections 5.7(a) and 5.7(g). Section 5.7(a) is the recurring budget for the upgrade or replacement of existing substation, line and communication equipment based on condition, age, test results and operating history. Section 5.7(g), High Load Readiness Equipment, is a load-growth-driven initiative for new reclosers and capacitor banks required to increase sectionalizing capability, support outage restoration and provide reactive power and voltage support.

As clarified in the response to IR-18, the commentary in the Application concerning new capacitor banks and reclosers for heavily loaded feeders was incorrectly placed in Section 5.7(a). That commentary pertains to Section 5.7(g). Equipment is assigned to the applicable budget based on its primary purpose: replacement or lifecycle renewal of existing equipment is recorded in Section 5.7(a), while incremental equipment installed for high-load readiness is recorded in Section 5.7(g).

b. No. A decrease in other distribution equipment budget areas is not expected as a direct result of the High Load Readiness project. Section 5.7(g) addresses incremental requirements created by load growth and does not replace the recurring need to renew existing equipment. The project may improve operational flexibility and reduce the consequences of outages on heavily loaded feeders, but it does not eliminate the underlying asset replacement and system expansion requirements budgeted elsewhere.

However, the reclosers installed through the High Load Readiness project may reduce the capital investment required for future distribution automation projects where the equipment placement and technical requirements of both initiatives align. These devices can support multiple purposes, including feeder sectionalizing, staged restoration and automated switching. In such circumstances, the existing reclosers may be incorporated into a future distribution automation scheme, reducing or avoiding the need to install additional switching devices. Any potential reduction would be project-specific and would depend on the location, configuration, communication capability and control requirements of the future distribution automation project.

IR-76 Section 6.2(a) - 69kV and 138 kV Switch Program

a. This section mentions an air switch inspection program –

i. Is this included in the capital budget, or is it an operational expense?
ii. If it is capitalized, can you please indicate the amount of the budget for this section that is related to the inspection and justify why it is capitalized?

Responses:

a. i. The switch inspection program referenced in Section 6.2(a) is included in the capital budget.

ii. Transmission switch inspections are completed primarily on an available-opportunity basis such as during planned outages, switching procedures and other such work. As such, the labour component of the budget related to inspections is relatively minor and not separately budgeted. Most of the labour budget in Section 6.2(a) is associated with the planned replacements and upgrades.

The transmission switch inspection work involves engineering and condition assessment activities undertaken to identify, evaluate and prioritize transmission and substation switches requiring replacement, refurbishment or upgrades under the 69 kV and 138 kV Switch Program. The inspections assess equipment condition, operational performance, deterioration mechanisms, safety concerns, and provide the information necessary to determine appropriate capital investment.

Consistent with utility asset management practice, condition assessment and inspection activities that are performed specifically to support capital asset replacement or upgrade decisions form part of the overall cost of planning and executing the associated capital program. The information obtained through the inspection process is used to identify assets requiring renewal, establish project scope, develop work plans, prioritize investments based on condition and risk, and support the efficient deployment of capital resources.

Accordingly, the inspection activities included in this section are directly attributable to the replacement and refurbishment of transmission and substation switching assets and are capitalized as part of the asset renewal program.

IR-77 Section 6.2(b) - Transmission Line Refurbishment

a. This section indicates that it provides for inspection of the transmission system:

i. Please indicate the amount of the budget for inspection activities, breaking down amounts for aerial, drone, and ground inspections.
ii. Please justify why this is included as a capital item rather than an operational expense.

Responses:

a. i. The budget for inspection activities is $260,000, with aerial inspection budgeted at $28,000, drone inspection budgeted at $86,000, and ground inspection budgeted at $146,000.

ii. The inspection activities included within Section 6.2(b) are consistent with common utility asset management practice, whereby condition assessment activities that are performed in direct support of a capital refurbishment or replacement program are included as part of the cost of developing and executing that capital project. The inspection results provide the engineering information required to determine which structures, conductors, hardware and associated components require replacement or upgrade, establish project scope, and prioritize investments based on asset condition and risk. As such, these costs are directly attributable to the associated capital program and are treated as part of the capital cost of renewing the transmission system.

IR-78 Section 7.1(b) - Operations Training Centre

a. You explain in your response to the Commission's previous interrogatories that previous training was completed in part by internal and external instructors – where did this training take place?

b. Can you please justify the need for a modular classroom as opposed to using an existing room in one of your facilities for the classroom-based portion of your new training program?

c. How often will PLT's undergo training in this program? Will it be in use consistently throughout the year?

Responses:

a. Previous training delivered by internal and external instructors took place at Maritime Electric facilities and operational work locations, depending on the subject matter. Classroom instruction was generally held in available meeting rooms, while practical training occurred at yards, substations, worksites, and other operational locations.

Although this approach supported individual training needs, it did not provide a dedicated, standardized environment for utility trades training. Training had to be scheduled around instructor availability, room availability, operational requirements, and access to suitable worksites. In addition, the existing practice of ad-hoc training does not allow field equipment, controls, and electrical systems to be safely configured or simulated for structured instruction and competency assessment. Adequate yard space at various Company facilities is not available anymore because of increased parking or storage requirements. Training provided at existing substations and work sites is not an appropriate means of training because there is not the ability to de-energize the substations to perform training safely.

The proposed training centre will address these limitations by providing a controlled, purpose-built environment where employees and training personnel can develop and demonstrate safety-critical skills before applying them in the field. It will support formal training in areas such as hot-line and rubber-glove work, equipotential bonding and grounding work methods, equipment operation, switching, safety procedures, emergency response, refresher training, and competency assessment.

For safety-critical utility work, continued reliance on available meeting rooms, active operational substations, and training opportunities arising through day-to-day work is not sufficient to support consistent workforce development, qualification, and ongoing competency evaluation.

b. The Company plans to establish the proposed training centre on the property acquired through the recently approved land exchange at Crossroads. The site will include a simulation yard, or in other words, an area that mimics a substation containing the infrastructure and equipment identified in Confidential Appendix Q-17, Section 7.1(b), Table 1. As the site is currently undeveloped and contains no existing buildings, a

dedicated classroom is required to support the delivery of both theoretical and practical training.

The classroom is a fundamental component of the proposed training centre. It will enable classroom instruction, demonstrations, safety briefings, competency assessments, and hands-on field exercises to be delivered within the same training environment. This integrated approach allows employees to move directly from instruction to practical application using the adjacent training infrastructure, improving knowledge retention, reinforcing safe work practices, and supporting more effective skills development.

Existing meeting rooms were designed for general administrative and business purposes and are not located near the proposed practical training facilities. Relying on those spaces would require the instructor and employees to travel between locations, reducing training effectiveness, disrupting continuity, and limiting the ability to seamlessly combine classroom and field-based learning. It would also create scheduling conflicts with normal business operations. In contrast, the proposed classroom will provide a dedicated space for technical training materials, instructional equipment, safety resources, demonstrations, and competency evaluations, ensuring the training centre can operate as a purpose-built workforce development facility.

The proposed training centre should therefore be viewed as a comprehensive utility training and development facility rather than simply the addition of classroom space. It will support Maritime Electric's transition from a predominantly on-the-job training model to a structured, standardized, and competency-based approach that improves workforce readiness, consistency, and safety performance.

In addition, Maritime Electric does not have access to a nearby utility training centre and cannot rely on regional third-party facilities to provide specialized electrical utility training in a cost-effective way. Maintaining an in-house training capability is therefore necessary to ensure the Company can efficiently develop current and future employees and sustain the technical and safety competencies required to operate and maintain the electrical system.

c. Power line technicians, electricians, and system and meter technicians are expected to use the facility on a recurring basis throughout the entire year. Training will include apprentice development, technical and safety instruction, annual refresher training, practical assessments, emergency response exercises, and competency verification. It will also accommodate first aid, safety training, contractor orientation, and emergency preparedness exercises that are difficult to deliver within existing facilities. The schedule will be based on apprentice training blocks, annual refresher requirements, competency assessment frequency, emergency response exercise frequency, and annual training day requirements.

Accordingly, the proposed training centre should not be viewed solely as a facility for occasional training events. It is intended to be a permanent utility workforce development facility that supports the Company's transition from a predominantly on-the-job training model to a more structured, standardized, and competency-based approach to workforce training and safety development in a safe and controlled environment.

IR-79 Section 7.2(a) - Hardware Acquisitions

a. It was mentioned in this section that the IT department became responsible for cybersecurity of the OT network starting in 2019. - Please present the costs of this program (including operational costs and the costs of replacing equipment) in the past three years since foundational work was completed. How does this compare to the estimated costs if cybersecurity had been outsourced for those years instead?

Responses:

a. The current cybersecurity model uses a combination of Maritime Electric efforts combined with external vendors and specialists. The Company's internal cyber team selects tools, coordinates testing and assessments, provides project management, investigates alerts, and manages backups and patching. Outside vendors provide independent assessments, incident response support, software and hardware tooling, and patch support.

Maritime Electric has not obtained a proposal for a fully outsourced information technology ("IT") and operations technology ("OT") cybersecurity service with a scope comparable to the Company's existing hybrid model. Accordingly, the Company cannot provide a reliable retrospective estimate without defining the required service scope, response obligations, OT access requirements, data-handling requirements, and retained internal responsibilities. Any unsupported estimate would not provide a meaningful comparison.

IT and OT cybersecurity costs are tracked under one capital project number. Table IR-79 shows an estimate of the IT and OT costs breakdown between operating and capital costs.

TABLE IR-79
Breakdown of IT and OT Cybersecurity Costs

Year	Operating (A)	Capital (B)	Total (C = A + B)
2023	$ 9,000	$ 407,000	$ 416,000
2024	$ 119,300	$ 301,000	$ 420,300
2025	$ 74,000	$ 846,000	$ 920,000

IR-80 Section 7.2(b) - Purchased Software and Upgrades

a. It is explained in this section that more and more IT applications are being moved to the Software as a Service model – i.e. on a subscription basis.

i. Please indicate which software listed in Table 104 are on a subscription basis, and how much of the budget for this section is related to subscriptions.
ii. Please justify why software subscriptions are included in the capital budget rather than operational expenses.
iii. The application mentions that this model "reduces the hardware required to host the software" – have you seen a decrease in the need/cost of hardware acquisitions since implementing this model? Please provide an estimate of the savings in the 2026 budget, if relevant.

Responses:

a. i. The explanation provided in Section 7.2(b) of the Application regarding a move towards Software as a Service ("SaaS") was given as a description of an industry trend that software vendors have adopted. It was meant to explain why some software is no longer included in the capital budget (e.g., Microsoft suite). None of the software listed in Table 104 of the Application are procured based on the SaaS model. They are all based on the on-premise model.

ii. As indicated in the response to IR-80(i), SaaS software is not included in the capital budget.

iii. As described, the SaaS model reduces the investment in on-premise hardware. In the SaaS model the vendor is responsible for providing the hardware and these costs are passed on as part of the subscription. As a result, the data center hardware required at Maritime Electric is expected to be less than if these applications were installed on-premise.

No relevant savings have been achieved to date as most SaaS tools were implemented after the last data center refresh in 2021. The next data center refresh is scheduled for 2028 (pending Commission approval).

IR-81 Section 7.2(c) - Cybersecurity Enhancements

a. This section describes a portion of the budget to "refresh" cybersecurity equipment that have been in place for five years. Please indicate how this section is different from section 7.2(a) Hardware Acquisitions, which also includes $340,000 to replace cybersecurity equipment.

b. The budget for this section is over two times bigger than the adjusted average of the previous five years. Please justify this increase.

Responses:

a. The equipment purchases referenced in Section 7.2c of the Application relate to the replacement of hardware in the OT data center that has reached the end of life. This includes the servers and storage for both the production and disaster recovery sites.

The hardware referenced in Section 7.2a of the Application relates to the replacement of communications equipment in a group of substations that have also reached end of life. The communication hardware supports cybersecurity monitoring, alerting and logging, among other services.

b. The variance between the 2026 cybersecurity enhancements budget and that of the previous year average is due primarily to two items:

- The replacement of the OT data center. The data center is on a five-year refresh cycle which ensures that hardware is under vendor support and that security patching is available.
- The implementation of Microsoft Purview. This solution will enable the IT team to monitor for personally identifiable information and other sensitive data.