All our energy.
All the time.

MARITIME ELECTRIC
A FORTIS COMPANY

August 2, 2024

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The Island Regulatory and Appeals Commission

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

Dear Commissioners:

Please find enclosed five copies of Maritime Electric's 2025 Capital Budget Application ("Capital Budget" or "Application").

The Capital Budget has been developed in accordance with the requirements of the Company's Capital Expenditure Justification Criteria and related Commission Order UE-17-03. In addition, as requested in the Commission's June 7, 2021 letter of direction concerning filing requirements for annual capital budget applications, the Application includes:

i. A summary of historical and current electricity rates, and a forecast of the impact that the proposed 2025 Capital Budget will have on electricity rates (Section 3.3);
ii. A breakdown of proposed capital expenditures by Investment Classification in Section 3.4 with supporting information in Appendix F;
iii. System reliability trends and comparisons to other Atlantic Canadian electric utilities in Section 3.5 a to c and Confidential Appendix Q-1;
iv. Identification of the feeders with the highest average annual outage hours over the past 10 years based on SAIDI reliability data and the capital projects and programs that will improve reliability performance on many of these feeders (Sections 3.5 d and e);
v. A summary of actual and forecast capital expenditures for the period 2016 to 2029, with breakdown to the major budget category level (i.e., Generation, Distribution, Transmission and Corporate), provided as Appendix A; and
vi. A listing of future capital projects with 2025 budget amounts and preliminary cost estimates for 2025 to 2029, provided as Appendix B.

If you have questions or require additional information concerning any aspect of the 2025 Capital Budget Application, please do not hesitate to contact me at 902-629-3641.

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

Gloria Crockett, CPA, CA
Director, Regulatory and
Financial Planning

GCC17
Attachments

**C A N A D A**

**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 2025 Capital Budget and for certain approvals incidental to such an order.

# APPLICATION AND EVIDENCE OF MARITIME ELECTRIC COMPANY, LIMITED

**August 2, 2024**

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| Legend of Abbreviations | |
|---|---|
| AACE | American Association of Cost Estimating |
| ACSR | Aluminum Conductor Steel Reinforced |
| AMI | Advanced Metering Infrastructure |
| amps | amperes |
| ASPE AcG-20 | ASPE Accounting Guideline 20 |
| Application | 2025 Capital Budget Application |
| ASPE | Canadian Accounting Standards for Private Enterprises |
| Atlantic Utilities | Atlantic Canadian Electric Utilities |
| ATV | All-Terrain Vehicle |
| BCC | Backup Control Centre |
| BGS | Borden Generating Station |
| CCAS | Climate Change Adaptation Strategy |
| CEJC | Capital Expenditure Justification Criteria |
| CGS | Charlottetown Generating Station |
| Commission | Island Regulatory and Appeals Commission |
| Company | Maritime Electric Company, Limited |
| COVID-19 | COVID-19 Pandemic |
| CRMP | Cyber Risk Management Program |
| CSA | Canadian Standards Association |
| CT1 | Combustion Turbine #1 |
| CT2 | Combustion Turbine #2 |
| CT3 | Combustion Turbine #3 |
| DAMP | Distribution Asset Management Program |
| DAS | Distribution Automation Systems |
| DC | Direct Current |
| DER | Distributed Energy Resources |
| Dorian | Hurricane Dorian |
| EC | Electricity Canada |
| ECC | Energy Control Centre |
| EPA | Energy Purchase Agreement |
| EIA | Environmental Impact Assessment |
| EV | Electric Vehicle |
| FERC | Federal Energy Regulatory Commission |
| Fiona | Hurricane Fiona |
| Fortis | Fortis Inc. |
| GAAP | Generally Accepted Accounting Principles |
| GEC | Capitalized General Expense |
| GIS | Geographic Information System |
| GP | Great Plains |
| GRA | General Rate Application |

| Legend of Abbreviations | |
|---|---|
| HSE | Health, Safety and Environmental |
| HVAC | Heating, Ventilation and Air Conditioning |
| IAS | International Accounting Standard |
| IDC | Interest During Construction |
| IEEE | Institute of Electrical and Electronics Engineers |
| Interconnection | PEI-NB Interconnection |
| IRAC | Island Regulatory and Appeals Commission |
| ISP | Integrated System Plan |
| IT | Information Technology |
| km | kilometre |
| kV | kilovolt |
| kW | kilowatt |
| kWh | kilowatt hour |
| LED | Light-Emitting Diode |
| Maritime Electric | Maritime Electric Company, Limited |
| MED | Major Event Day |
| MHz | Megahertz |
| MVA | megavolt ampere |
| MW | megawatt |
| NB | New Brunswick |
| OHPA | Oil to Heat Pump Affordability |
| OT | Operations Technology |
| P&C | Protection and Control |
| PCB | Polychlorinated Biphenyl |
| PEI | Prince Edward Island |
| PEIEC | Prince Edward Island Energy Corporation |
| PHEV | Plug-in Hybrid Electric Vehicle |
| Point Lepreau | Point Lepreau Nuclear Generating Station |
| PPE | Property, Plant and Equipment |
| ppm | parts per million |
| RF | Radio Frequency |
| RFP | Request for Proposal |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SCADA | Supervisory Control and Data Acquisition |
| SCBR | Supplemental Capital Budget Request |
| US | United States |
| USofA | Uniform System of Accounts |
| WRSC | West Royalty Service Centre |

# 1.0 APPLICATION

**C A N A D A**

**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 2025 Capital Budget and for certain approvals incidental to such an order.

## Introduction

Maritime Electric Company, Limited ("Maritime Electric" or the “Company”) is a Corporation incorporated under the laws of Canada with its head or registered office at Charlottetown and carries on a business as a public utility subject to the *Electric Power 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 the capital budget for the year 2025 as outlined in the attached evidence.

The proposals contained in this Application represent a just and reasonable balance of the interests of Maritime Electric and those of its customers and will, if approved, allow the Company to perform necessary capital additions and improvements at a cost that is, in all circumstances, reasonable.

**Procedure**

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

Dated at Charlottetown, Province of Prince Edward Island, this 2nd day of August, 2024.

**D. Spencer Campbell, Q. 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 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 2025 Capital Budget and for certain approvals incidental to such an order.

**AFFIDAVIT**

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

We are the President and Chief Executive Officer, Vice-President, Corporate Planning and Energy Supply, Vice-President, Sustainability and Customer Operations, and Vice-President, Finance and Chief Financial Officer of Maritime Electric, 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.

## 2.0 AFFIDAVIT

We prepared or supervised the preparation of the evidence and to the best of our knowledge the evidence is true in substance and in fact. A copy of the evidence is attached to this, our Affidavit, and is collectively known as Exhibit "A", contained in Sections 3 through 9 inclusive, Appendices A through P inclusive, and Confidential Appendices Q-1 through Q-17 inclusive.

Section 10 contains a proposed Order of the Commission based on the Company's Application.

SWORN TO SEVERALLY at
Charlottetown, Province of Prince Edward Island,
the 2nd day of August, 2024.
Before me:

____________________________
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 INTRODUCTION

## 3.1 Corporate Profile

Maritime Electric owns and operates a fully integrated 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 electrical utility on PEI delivering approximately 90 per cent of the electricity supplied in the province. To meet the energy demand and supply requirements of its customers, the Company has contractual entitlement to capacity and energy from NB Power's Point Lepreau Nuclear Generating Station ("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. Through various contracts with the PEI Energy Corporation ("PEIEC"), the Company purchases the capacity and energy from 92.5 megawatts ("MW") of wind generation on PEI. In the event that the wind 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 PEI's *Electric Power Act*. As a public utility, the Company is subject to regulatory oversight and approvals of IRAC, which has jurisdiction to regulate public utilities under the *Electric Power Act* and the *Island Regulatory and Appeals Commission Act.*

## 3.2 Overview of Evidence

Under Section 17 (1) of the *Electric Power Act*, every public utility is required to submit to the Commission, for its approval, an annual capital budget of proposed improvements or additions to its property. This is the evidence in support of Maritime Electric's 2025 Capital Budget Application ("Application"). In preparing this evidence, the Company used the Capital Expenditure Justification Criteria ("CEJC") filed on April 10, 2018 and updated on November 22, 2019. Accordingly, for each proposed capital project, the evidence will indicate whether the project is considered mandatory, recurring, justifiable or work support services. Also, Section 3.4 provides the 2025 Capital Budget according to the Investment Classifications proposed by the Commission in a letter of direction dated June 7, 2021.

This Application has been developed to address a range of system and business requirements that support the Company's ability to fulfil its obligation as a public utility under Section 3a of the *Electric Power Act* 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;"

Capital investment in the electrical system, and the facilities and equipment that support the operation of the system, is an annually recurring necessity for the Company to comply with this obligation. Through capital investment, the Company is able to serve existing and new customers, modify the system as necessary to meet customer demand, replace or upgrade aged, deteriorated or obsolete assets in a structured manner, improve system performance through design and technology enhancements, adapt to climate change, and ensure that the work support services to meet business and regulatory requirements are in place and adequate.

It is important that the Company strategically allocates the annual capital investment to meet the needs across the primary categories of the Application (i.e., Generation, Distribution, Transmission and Corporate). This is accomplished using structured planning resources such as the Integrated System Plan ("ISP") and the Distribution Asset Management Program ("DAMP") as outlined in Section 3.6a, as well as information collected through operations (e.g., inspection programs), and projects designed to identify and assess equipment or system deficiencies (e.g., engineering studies, cybersecurity reviews, climate change vulnerability assessments, etc.).

The Company's capital investments are also dictated by some mandatory activities as a result of legislation or regulatory direction. These are often to address safety or environmental issues, but orders of the Commission can also result in mandatory capital investments.

Appendix A outlines the Company's actual and proposed capital expenditures from 2016 to 2029, and Appendix B provides preliminary budget estimates for future capital projects.[1]

Table 1 outlines the proposed capital expenditures for 2025.

**TABLE 1**
**Proposed 2025 Capital Expenditures**

| | | | |
|---|---|---|---|
| **4.0** | **Generation** | | |
| | 4.1 | Charlottetown Generating Station – Buildings and Site Services | $ 350,000 |
| | 4.2 | Charlottetown Generating Station – Turbine Generator | 493,000 |
| | 4.3 | Borden-Carleton Generating Station – Buildings and Site Services | 65,000 |
| | 4.4 | Borden-Carleton Generating Station – Turbine Generators | 229,000 |
| | | | 1,137,000 |
| **5.0** | **Distribution** | | |
| | 5.1 | Replacements Due to Storms, Collisions, Fire and Road Alterations | 2,224,000 |
| | 5.2 | Distribution Transformers | 15,908,000 |
| | 5.3 | Services and Street Lighting | 9,702,000 |
| | 5.4 | Line Extensions | 3,644,000 |
| | 5.5 | Line Rebuilds | 6,813,000 |
| | 5.6 | System Meters | 805,000 |
| | 5.7 | Distribution Equipment | 1,573,000 |
| | 5.8 | Transportation Equipment | 3,103,000 |
| | | | 43,772,000 |
| **6.0** | **Transmission** | | |
| | 6.1 | Substation Projects | 19,565,000 |
| | 6.2 | Transmission Projects | 7,467,000 |
| | | | 27,032,000 |
| **7.0** | **Corporate** | | |
| | 7.1 | Corporate Services | 872,000 |
| | 7.2 | Information Technology | 2,131,000 |
| | | | 3,003,000 |
| **Sub-total** | | | $ 74,944,000 |
| **8.0** | **Capitalized General Expense** | | 919,000 |
| **9.0** | **Interest During Construction** | | 869,000 |
| Less: Customer Contributions[a] | | | (1,550,000) |
| **TOTAL** | | | **$ 75,182,000** |

a. Five-year average, calculated from actual and budgeted contributions from 2020 to 2024, normalized to 2025 dollars using an annual escalation rate of 3 per cent.

[1] The preliminary budget estimates for future capital projects provided in Appendix B are subject to change in future applications, as detailed scoping and costing have not yet been completed.

Figure 1 shows the proposed 2025 capital expenditures by origin.

**FIGURE 1**
**Proposed 2025 Capital Expenditures by Origin**

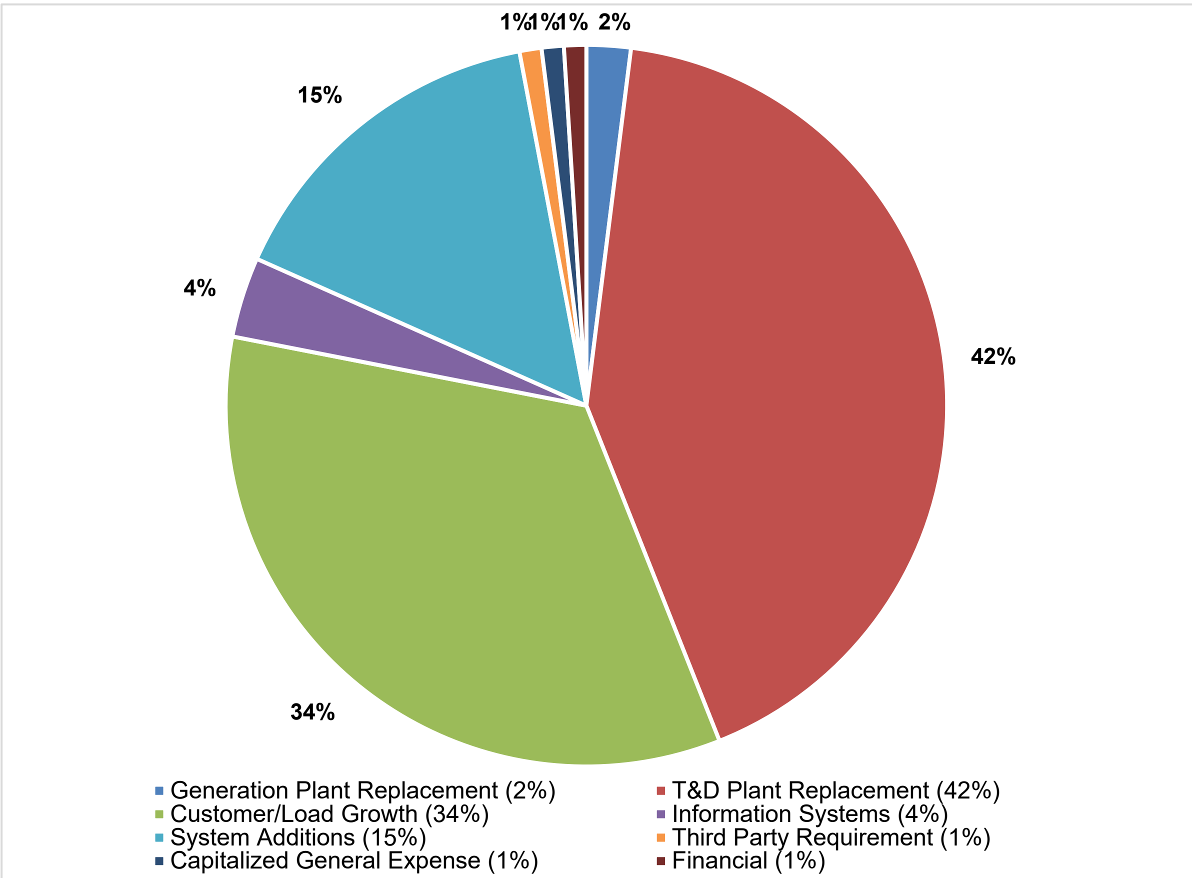
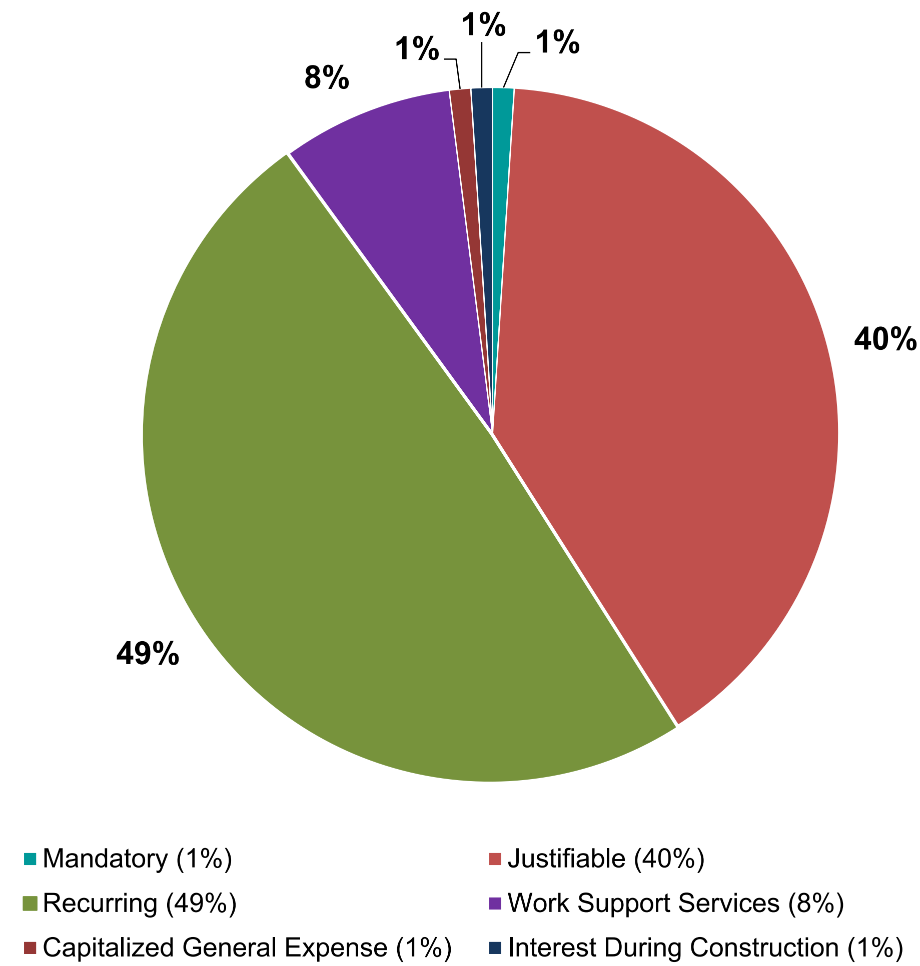



Figure 2 shows the proposed 2025 capital expenditures, before customer contributions, by CEJC classification.

**FIGURE 2**
**Proposed 2024 Capital Expenditures by CEJC Classification**




An expanded breakdown of the proposed 2025 capital expenditures by CEJC classification is provided in Appendix C.

A map of the current electrical system showing the major supply system components and the location of the proposed 2025 capital expenditures is provided as Appendix D. Some expenditures involving work throughout the province cannot be assigned to one location and are therefore not shown on the map. This applies to Sections 5.1, 5.2, 5.3, 5.4a, 5.5b-e, 5.6, 5.7, 5.8, 6.1i(v), 6.1I, 6.2a-b, 6.2d, 6.2e, 7.1a and 7.2a-f of this Application.

### 3.3 Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

In accordance with the CEJC, this section provides an estimate of the impact of the proposed 2025 Capital Budget on rate base, revenue requirement and customer rates.

The proposed 2025 Capital Budget of $75.2 million, per Table 1, is higher than the expected total 2025 Capital Budget forecast in Table 4-6 of the General Rate Application ("GRA") approved by the Commission by Order UE20946. However, this will not impact the rates approved under the current GRA, as discussed herein.

The proposed 2025 Capital Budget will impact the Company's revenue requirement by the incremental depreciation expense, cost of capital, and income tax charges associated with it. However, those incremental increases are expected to be offset through sales growth and operational efficiencies during the remainder of the rate-setting period.

Therefore, approval of the Application as filed will not require any customer rate increase until the next GRA is filed.

Table 2 provides an estimate of the impact of the proposed 2025 Capital Budget on the forecast 2025 rate base that was included in the Company's current GRA.

**TABLE 2**
**Estimated Impact on 2025 Year End Rate Base**

| | | |
|---|---|---|
| Estimated Impact on Rate Base (000s) | A | $66,392 |
| 2025 Forecast Year End Rate Base (000s) | B | $537,615 |
| Percentage of 2025 Forecast Year End Rate Base | C = A/B | 12.35% |

The supporting calculations for Table 2 can be found on page 3 of Appendix E.

Table 3 provides an estimate of the increase in revenue requirement associated with the proposed 2025 Capital Budget that is included in the Company's 2025 revenue requirement forecast from the currently approved GRA.

| TABLE 3<br>Estimated Impact on 2025 Revenue Requirement | | |
|---|---|---|
| Estimated Impact on Annual Revenue Requirement (000s) | A | $7,825 |
| 2025 Forecast Revenue Requirement (000s) | B | $271,927 |
| Percentage Increase in 2025 Forecast Revenue Requirement | C = A/B | 2.88% |

The supporting calculations for Table 3 can be found on page 4 of Appendix E. It should be noted that the estimated revenue requirement does not consider potential higher revenues from customer growth projects or the long-term benefit of a fully justified capital expenditure program on minimizing aggregate costs and consequently, revenue requirement.

If approved, the estimated increase in revenue requirement will be recovered from customers through the rates and charges for electrical service. Table 4 shows the estimated impact on revenue requirement expressed as a rate per kilowatt hour (“kWh”).

| TABLE 4<br>Estimated Revenue Requirement Expressed as a Rate per kWh | | |
|---|---|---|
| Estimated Impact on Revenue Requirement (000s) | A | $7,825 |
| 2025 Forecast Sales (gigawatt hour) | B | 1,606,372 |
| Increase in Revenue Requirement ($/kWh) | C = A/B | $0.00487 |

The supporting calculations for Table 4 can be found on page 5 of Appendix E.

Using the rate per kWh calculated above, Table 5 provides an estimate of the increase in annual cost for electrical service for a customer in Maritime Electric’s residential and general service rate classes based on a benchmark energy consumption.

| TABLE 5<br>Estimated Cost Increase by Customer Class | |
|---|---|
| Annual Cost Increase for a Residential Customer, before tax[2] | $37.99 |
| Annual Cost Increase for a General Service Customer, before tax[3] | $584.40 |
| % Increase in Annual Cost for Rural Residential Customer | 2.29% |
| % Increase in Annual Cost for Urban Residential Customer | 2.33% |
| % Increase in Annual Cost for General Service Customer | 2.25% |

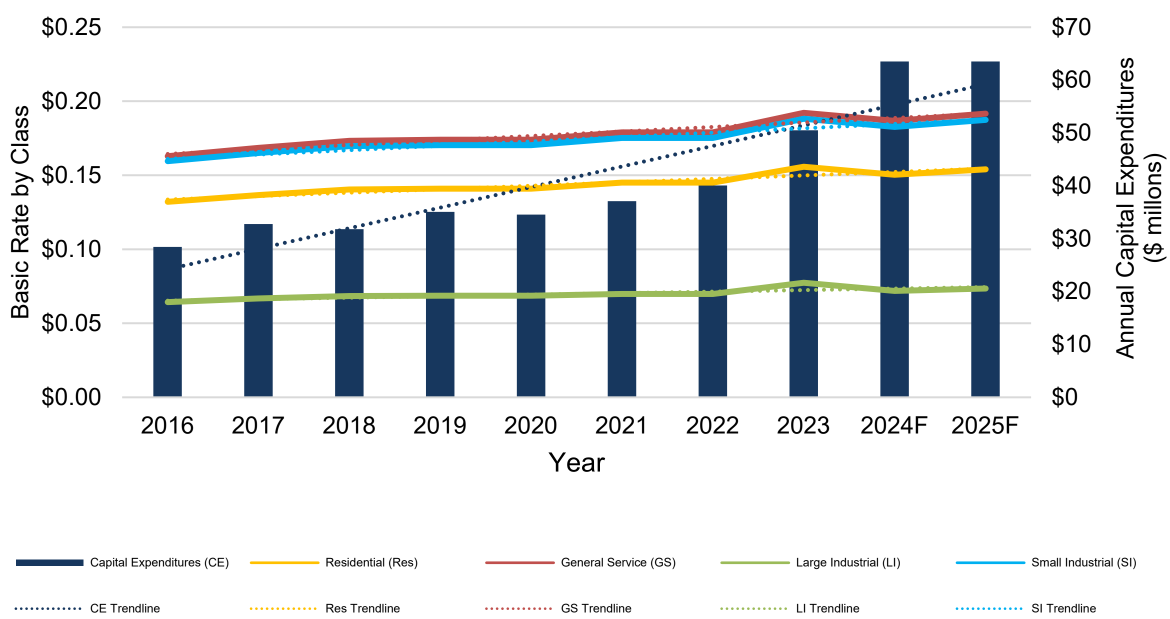
The supporting calculations for Table 5 can be found on page 5 of Appendix E.

Revenue requirement is the amount of revenue required from customers to cover the utility's cost of serving those customers, which includes operating costs, depreciation, financing charges, incomes taxes and the allowed return for the shareholder. Approved customer basic rates are set to recover the Company's forecast revenue requirement based on the forecast of customers' energy and demand.

Figure 3 shows the actual historical capital expenditures since 2016, forecast expenditures for 2024 based on the approved 2024 Capital Budget, and the 2025 Capital Budget as proposed in this Application. Figure 3 also shows the energy charge per kWh over the same period for the four largest customer classes.[4]

[2] Based on a benchmark consumption of 650 kWh per month.
[3] Based on a benchmark consumption of 10,000 kWh per month and demand of 50 kilowatts ("kW") per month.
[4] For customer classes with multiple energy rate blocks, only the first rate block is shown in Figure 3.

**FIGURE 3**
**Capital Expenditure and Basic Rates by Class**




As shown by the capital expenditure trendline in Figure 3, the Company's capital investment has increased since 2016. Many factors influence customer rates and the relationship between a utility's investment in capital and customer rates is complex. The most direct impact of capital investment on rates is annual depreciation expense. However, additional revenue from increased sales driven by customer growth, and reduced maintenance costs resulting from capital upgrades, help to temper that rate impact. As such, the slope of the trendlines for customer basic rates over the same period are significantly less than the capital expenditure trendline.

For the proposed 2025 Capital Budget Application, the increase over the estimated capital expenditures in the approved GRA are expected to be absorbed through sales growth and operational efficiencies.

A fully justified capital expenditure program combined with efficient operations will minimize revenue requirement and provide the least cost electricity to ratepayers.

### 3.4 Capital Budget by Investment Classification

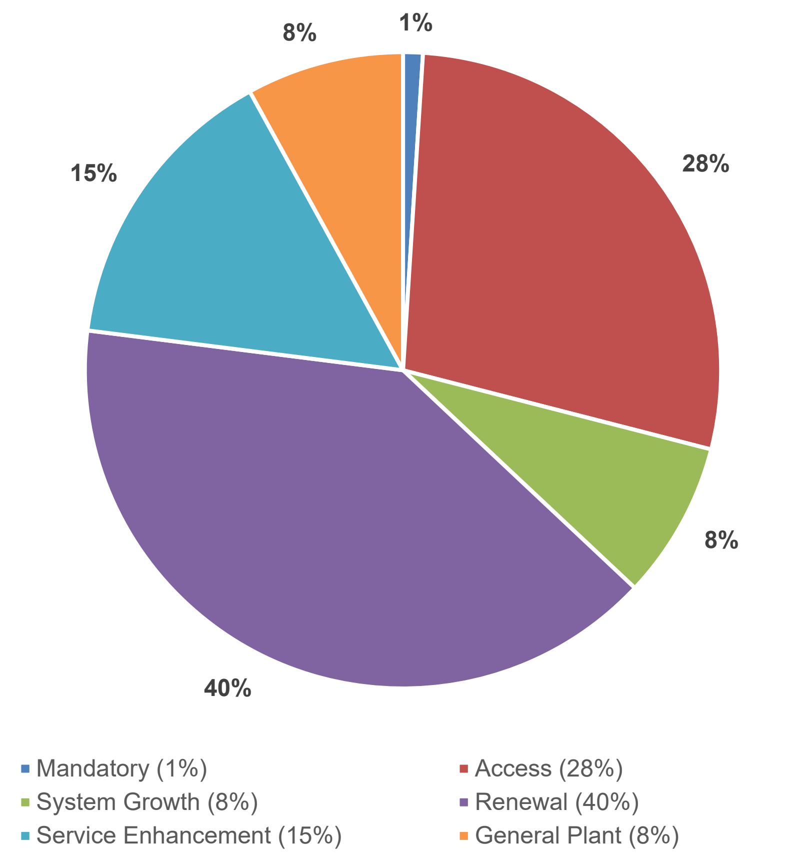
In a letter of direction to Maritime Electric dated June 7, 2021, the Commission provided the Company with Investment Classifications to organize the projects and expenditures proposed in future capital budget applications. The Investment Classifications as identified and described in the letter of direction are repeated in Table 6.

**TABLE 6**
**Investment Classification Descriptions**

| Investment Classification | Description |
|---|---|
| Mandatory | Investments that are prescribed by a governing body, such as the Provincial Government or the Commission. |
| Access | Investments modifying (including asset relocations) the Company's electrical system that the Company is obligated to perform to provide a customer or group of customers with access to electrical service. |
| System Growth | Investments that are modifications to the Company's system to meet forecast changes in customer electricity resource requirements. |
| Renewal | Investments replacing and/or refurbishing system assets on a like-for-like basis to extend their service life, and thereby maintain the ability to provide customers with their current electrical services. |
| Service Enhancement | Investments that are modifications to the Company's system to meet system operations requirements in a more efficient and/or effective manner. |
| General Plant | Investments in the Company's assets that are not part of its generation, transmission and distribution system, including land and buildings, tools and equipment, and electronic devices and software used to support day-to-day business and operations activities. |

Figure 4 shows the percentage breakdown of the 2025 Capital Budget by Investment Classification, which is provided in detail in Appendix F. While the Investment Classifications appear similar to the Capital Expenditures by Origin categories shown in Figure 1 of Section 3.2, a direct comparison should not be made for some categories as the methodology used to assign a capital budget item to an Investment Classification or Capital Expenditure by Origin category is materially different. For example, the Customer Load Growth category of Capital Expenditures by Origin includes a significant portion of new service connection costs (also including associated transformers and meter equipment) whereas those same costs are included in the Access category of Investment Classifications.

**FIGURE 4**
**2025 Capital Expenditures by Investment Classification**




Proposed expenditures in each of the Investment Classifications are driven by capital projects, programs and activities in the underlying Generation, Distribution, Transmission and Corporate categories and are discussed as follows.

<u>Mandatory</u>

Planned expenditures in the Mandatory classification represent approximately 1 per cent of the 2025 Capital Budget. There is one Mandatory project in the Distribution category, which involves removing electrical equipment from service that contains polychlorinated biphenyl ("PCB") at a concentration above 50 parts per million ("ppm"), as required by Federal Government legislation. In the Transmission category, the substation oil contaminant program is classified as Mandatory, as its objective is to comply with the PEI

*Environmental Protection Act* by preventing the discharge of a contaminant into the environment.

Access

Planned expenditures in the Access classification represent approximately 28 per cent of the 2025 Capital Budget and are primarily driven from the Distribution category. Access activities tend to be related to:

i. Customer requested work (e.g., service connections requiring transformers and meters, street and area lighting, and customer driven line extensions); and
ii. Third-party requirements (e.g., system modifications to accommodate road alterations and make-ready work for communication companies).

While the direction of the Commission is to classify each capital project or expenditure into one of the Investment Classifications, an exception has been made for distribution transformers and system meters. For distribution transformers, a portion of the proposed budget is allocated to the Mandatory classification, as it will be used to remove and replace transformers containing PCB. The remaining balance of the distribution transformers and the system meters budgets are proportionally allocated to the Access and Renewal classifications in accordance with the forecast transformer and meter quantities planned for addition or replacement. These exceptions were made to more accurately reflect actual expenditures on transformers and meters, whereas the same multi-classification allocation cannot be done for other budget items without subjective estimation. For distribution transformers, the budget allocation is approximately 5 per cent Mandatory, 47.5 per cent Access and 47.5 per cent Renewal. For system meters, 64 per cent of the budget for watt-hour and combination meters is allocated to Access and 36 per cent is allocated to Renewal.

System Growth

Planned expenditures in the System Growth classification represent approximately 8 per cent of the 2025 Capital Budget, with four projects in the Transmission category, including the Lorne Valley switching station expansion, Scotchfort substation, power transformer additions to the Wellington and Marshfield substations, and Y-119 extension to Scotchfort.

Renewal

Planned expenditures in the Renewal classification represent approximately 40 per cent of the 2025 Capital Budget, distributed across the Generation, Distribution, and Transmission categories. In Generation, renewal projects are required to ensure that the Company's three combustion turbines are ready to operate when required. In Distribution, Renewal expenditures are associated with replacements due to storms, fires and collisions, polemount and padmount transformer replacements, distribution line rebuilds, distribution line/equipment refurbishment and replacement programs, and system meters that are not allocated to Access. In Transmission, Renewal projects are planned to replace, rebuild, refurbish, and modernize substation facilities and transmission line assets to current operating and safety standards.

Service Enhancement

Planned expenditures in the Service Enhancement classification represent approximately 15 per cent of the 2025 Capital Budget, with all projects in the Distribution and Transmission categories. In Distribution, service enhancement includes reliability driven line extension projects, distribution corridor widening, and satellite-based vegetation imaging. In Transmission, it includes the Woodstock switching station project, communication fibre expansion, transmission corridor widening, and satellite-based vegetation imaging.

General Plant

Planned expenditures in the General Plant classification represent approximately 8 per cent of the 2025 Capital Budget, distributed across the Generation, Distribution and Corporate categories. In Generation, general plant projects are required to upgrade, restore and replace various building, site, and facility components that are necessary to support generation at that station. In Distribution, general plant expenditures are proposed to provide the tools and equipment required by operations personnel, as well as the transportation equipment required across all departments. All projects in the Corporate category (i.e., all Corporate Services and Information Technology projects) fall within the General Plant classification.

## 3.5 System Reliability Performance and Improvement

### a. System Average Interruption Duration Index

The primary metric used by Maritime Electric for measuring its reliability performance is System Average Interruption Duration Index ("SAIDI"),[5] which reflects the total outage time experienced by the average customer over a period of one year. There are two SAIDI indices commonly used by utilities: (i) SAIDI (All In) measures reliability performance using outage data collected under all operating conditions; and (ii) SAIDI (MED Excluded) modifies the outage data by removing significant outage events to reflect reliability performance under normal operating conditions (i.e., blue-sky days). When a significant outage event that meets the criteria of a major event day ("MED") occurs, the customer outage time associated with that event is not included in the resulting SAIDI (MED Excluded). SAIDI (MED Excluded) was developed by the Institute of Electrical and Electronics Engineers ("IEEE") to address large outage data variances caused by major system disturbances that if otherwise included would make it difficult to track changes to the reliability performance of the electrical supply system under normal operating conditions.

Historical SAIDI Performance

The SAIDI (All In) and SAIDI (MED Excluded) experienced by Maritime Electric customers over the ten-year period from 2014 to 2023 is shown in Figures 5 and 6, respectively. The SAIDI (MED Excluded) data also excludes externally caused outages,[6] which are typically infrequent, with only one such occurrence between 2014 and 2023. (Given the widespread system impact of an externally caused outage, it would be uncommon for it not to be recorded as a MED.)

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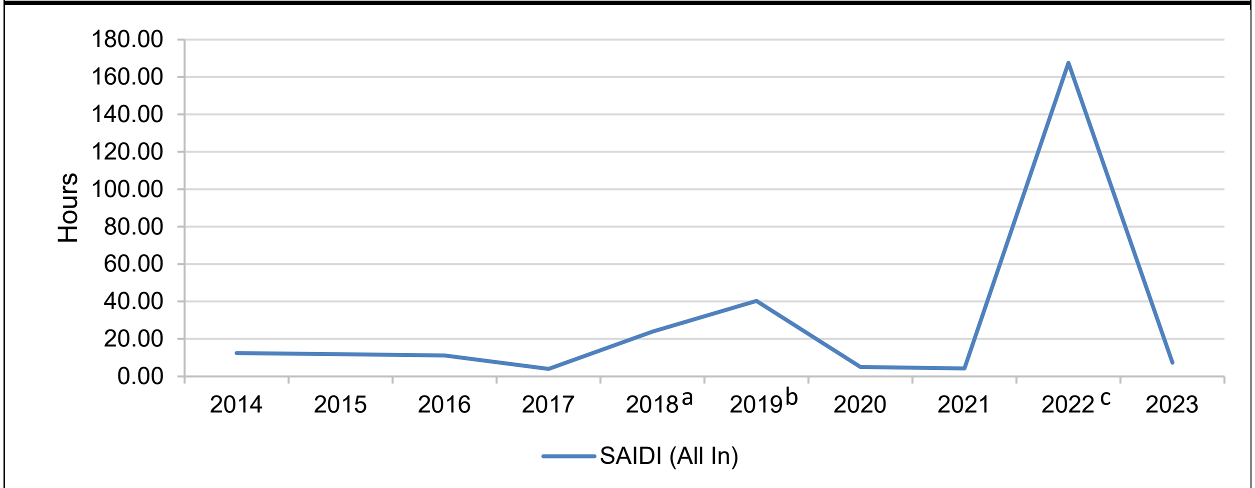
[5] Maritime Electric collects data for reporting on another reliability metric (i.e., System Average Interruption Frequency Index or "SAIFI"), but it does not use SAIFI for measuring reliability performance. This is further discussed in Section 3.5b, herein.

[6] An externally caused outage for Maritime Electric is an outage resulting from the loss of supply from NB Power.

Figure 5 shows that SAIDI (All In) has been highly variable since 2018, which reflects an increased frequency and severity of major storm events. This exposure highlights the importance of systematically identifying and replacing aged and deteriorated system components, as well as ensuring the electrical system is being upgraded to current standards whenever planned and unplanned replacements allow.

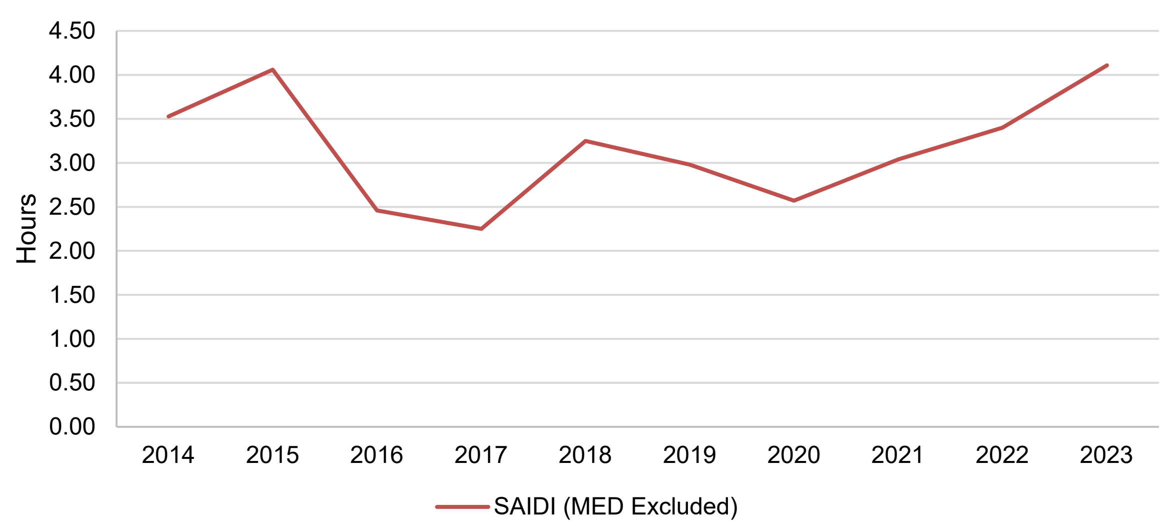
**FIGURE 5**
**SAIDI (All In) Performance 2014 to 2023**




a. The SAIDI impact resulting from a severe wind, snow and ice storm in November 2018 was 14.07.
b. The SAIDI impact resulting from Hurricane Dorian (“Dorian”) in September 2019 was 35.82.
c. The SAIDI impact resulting from Hurricane Fiona (“Fiona”) in September 2022 was 156.58.

Figure 6 shows that SAIDI (MED Excluded) reliability of the electrical system under normal operating conditions over the past ten years. Since 2017, SAIDI (MED Excluded) has been trending upward; however, this is partly attributable to major storm after-effects, such as when storm weakened trees and system components cause outages, sometimes weeks or months later.

**FIGURE 6**
**SAIDI (MED Excluded) Performance 2014 to 2023**




The reliability of Maritime Electric's electrical system under normal operating conditions, SAIDI (MED Excluded), reflects the Company's diligence in monitoring performance metrics and responding with the appropriate balance of operating controls and capital investments. Operating controls are applied to improve reliability through outage avoidance (e.g., live line work methods) and outage response (i.e., prompt and strategic to isolate problems quickly). Capital investments help to ensure that aged, deteriorated or overloaded components are replaced in a timely manner and provide for other system improvements that benefit customers over the life cycle of these investments.

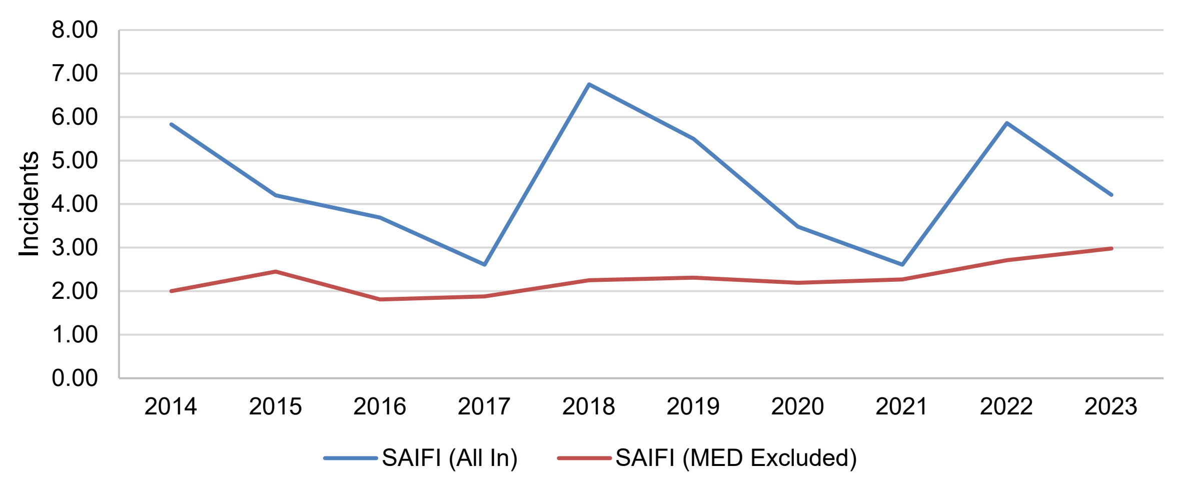
**b.** **<u>System Average Interruption Frequency Index</u>**

A second reliability performance metric that Maritime Electric collects data and reports on is System Average Interruption Frequency Index ("SAIFI"). SAIFI reflects the number of interruptions to the average customer over a one-year period. Like SAIDI, SAIFI can be reported for all operating conditions or with MEDs excluded. While (as previously indicated) Maritime Electric only uses SAIDI for measuring reliability performance, it records data for reporting on SAIDI and SAIFI to Electricity Canada ("EC") and the Commission.

Historical SAIFI Performance

Figure 7 provides the SAIFI (All In) and the SAIFI (MED Excluded) as experienced by Maritime Electric customers over the ten-year period 2014 to 2023. As with SAIDI, externally caused outages are included in the SAIFI (MED excluded) data.

**FIGURE 7**
**SAIFI Performance 2014 to 2023**




There are some deficiencies in Maritime Electric's SAIFI records due to limitations within the Company's outage management software. These deficiencies are more pronounced with the SAIFI (All In); however, it also affects the SAIFI (MED Excluded) data. Future investment in the Company's outage management software will be necessary to support the utilization of SAIFI as a reliability performance metric.

**c. <u>Benchmarking Against Similar Utilities</u>**

Maritime Electric's SAIDI and SAIFI performance compared to the average performance of other Atlantic Canadian electrical utilities ("Atlantic Utilities"), for the period 2014 to 2023, is provided in Figures 1 to 4 of Confidential Appendix Q-1.[7]

[7] Information on the reliability performance of other Atlantic Utilities was obtained through EC and is confidential to EC member utilities.

Maritime Electric monitors and measures reliability performance by comparing its reliability metrics with that of neighbouring Atlantic Utilities. The Company uses the moving average technique to identify trends in a reliability data set. Over the last five years, the moving average of Maritime Electric's SAIDI (MED Excluded) and SAIFI (MED Excluded), as provided in Figures 5 and 6 of Confidential Appendix Q-1, have been relatively stable with just a small upward trend. This indicates that the Company's reliability performance under normal operating conditions is reasonable and that past and present projects (e.g., new substations, distribution circuits, transmission lines, etc.) and programs (e.g., porcelain cutout replacement, eastern cedar pole replacement, line rebuilds, spill prevention, transmission and distribution line refurbishment, etc.) have been effective in achieving SAIDI (MED Excluded) reliability performance that has been better than the average of neighbouring Atlantic Utilities.

While the Company's SAIDI (MED Excluded) reliability performance has been good over the last five years, the moving average of SAIDI (All In) and SAIFI (All In), as shown in Figures 7 and 8 of Confidential Appendix Q-1, have generally been above the Atlantic Utilities average. This indicates that major weather events, such as ice or wind storms and system outage events on large radial feeders, are having a negative impact on reliability performance. In Maritime Electric's view, assessing the Company's reliability performance to be equal to, or better than, the Atlantic Utilities average is a reasonable indicator of service quality and is consistent with the Company's obligation under the *Electric Power Act* to at all times provide reasonably safe and adequate service as changing conditions require. As such, the Company has been focusing its efforts on improving SAIDI (All In) reliability performance.

Looking forward, the Canadian Standards Association ("CSA") has identified that "ice, snow and wind loads are perceived as the highest, most prevalent climate risk to the electrical sector across Canada."[8] Maritime Electric along with other key stakeholders are engaged with CSA as it undertakes extensive research and

[8] CSA Cross Country Stakeholder Workshop Phase II Final Report.

consultation concerning climate-related risks, impacts and best practices relevant to the Canadian electrical sector. This, along with a Climate Change Vulnerability Assessment that was completed by the Company in 2022, is being used to assess the Company's climate change risks and guide the Company's efforts to proactively mitigate any threats to the reliability performance of the electrical system. An example of climate change mitigation in the Application is programs in the Distribution and Transmission sections to widen vegetation management corridors beyond the public right-of-way and remove danger trees on private land, with landowner permission. These programs will improve system resiliency in the future during extreme weather events, such as Fiona.

**d. Feeder Reliability Performance**

Maritime Electric regularly compares feeder reliability performance to help identify where distribution system improvements are needed. This is done by gathering distribution outage data for a given period, subtotalling the data by feeder, and sorting the feeders based on average annual SAIDI contribution. Results change regularly depending upon the period analyzed, as new data is being generated with every outage. Using this approach, the SAIDI and SAIFI for Maritime Electric's ten feeders with the highest outage hours over the period 2014 to 2023 were calculated and are listed in Tables 7 and 8. The feeders identified in the tables can be compared with Maritime Electric's average feeder reliability performance (also shown in the tables).

Outage hours resulting from transmission and substation outages are upstream of feeders, and as such, are not relevant when identifying where feeder improvements are needed. For this reason, outage hours resulting from transmission and substation outages are excluded from the feeder data in both tables.

Outage records for feeders that were subdivided over the ten-year review period have been adjusted such that only the outages hours associated with the current feeder configuration are included (provided that sufficient data was available). This adjustment enables Maritime Electric to better identify and target areas where distribution system improvements are required.

The feeders with the highest outage hours under all operating conditions for the period 2014 to 2023 are shown in Table 7.

| TABLE 7<br>Feeders with Highest Outage Hours from 2014 to 2023 Under All Operating Conditions | | | | | |
|---|---|---|---|---|---|
| **Circuit** | **Feeder** | **Average Yearly SAIDI Contribution** | **Average Yearly SAIFI Contribution** | **Feeder Length (km)** | **Customer Count** |
| **Maritime Electric Average Feeder** | | **0.076** | **0.025** | **65** | **1,174** |
| Irishtown | KN80400 | 0.323 | 0.075 | 179 | 2,484 |
| Tignish West | AL00295 | 0.280 | 0.068 | 251 | 3,085 |
| Cavendish | BG56300 | 0.251 | 0.051 | 58 | 1,482 |
| Eldon-Belfast | VC01440 | 0.237 | 0.049 | 212 | 1,635 |
| Crapaud | AB33125 | 0.188 | 0.052 | 104 | 1,316 |
| Wellington East | WL02088 | 0.173 | 0.032 | 126 | 1,670 |
| Bedeque | AB33127 | 0.170 | 0.058 | 141 | 1,682 |
| Wellington West | WL02002 | 0.148 | 0.031 | 220 | 1,949 |
| Queens Arms | QA02700 | 0.146 | 0.053 | 28 | 3,595 |
| Wood Islands | DV19005 | 0.136 | 0.052 | 136 | 1,459 |

The feeders with the highest outage hours excluding MEDs and externally caused outages, for the period 2014 to 2023, are shown in Table 8.

| TABLE 8<br>Feeders with Highest Outage Hours from 2014 to 2023 Excluding MEDs<br>and Externally Caused Outages | | | | | |
|---|---|---|---|---|---|
| **Circuit** | **Feeder** | **Average Yearly SAIDI Contribution** | **Average Yearly SAIFI Contribution** | **Feeder Length (km)** | **Customer Count** |
| **Maritime Electric Average Feeder** | | **0.031** | **0.018** | **65** | **1,174** |
| Crapaud | AB33125 | 0.103 | 0.037 | 104 | 1,316 |
| Tignish West | AL00295 | 0.091 | 0.051 | 251 | 3,085 |
| Cavendish | BG56300 | 0.078 | 0.031 | 58 | 1,482 |
| Eldon-Belfast | VC01440 | 0.086 | 0.034 | 212 | 1,635 |
| Bedeque | AB33127 | 0.080 | 0.044 | 141 | 1,682 |
| Wood Islands | DV19005 | 0.057 | 0.032 | 136 | 1,459 |
| Irishtown | KN80400 | 0.062 | 0.038 | 179 | 2,484 |
| Mount Stewart | SF01190 | 0.059 | 0.024 | 136 | 1,296 |
| Commercial Road | VC02340 | 0.043 | 0.023 | 117 | 946 |
| Bedford Road | SF01197 | 0.041 | 0.016 | 39 | 409 |

### e. Feeder Reliability Improvements Proposed for 2025

Feeder reliability performance improvement in 2025 will be achieved through the completion of the Company's recurring capital programs, including load and reliability driven line extensions, single and three phase line rebuilds, distribution line refurbishment, eastern cedar pole replacement, deteriorated conductor replacement, backlot feed relocation and distribution corridor widening.

Regarding the specific feeders listed in Table 7 and 8, many are being, or will be, addressed through current and future distribution system upgrade projects. Examples include: the Tignish substation project, which was approved as part of the 2023 Capital Budget, will address the Tignish West feeder; the Blue Shank Road three phase conversion project proposed in Section 5.4b(i) of this Application will improve the Bedeque feeder; and the Irishtown Road three phase conversion will improve the Irishtown feeder in 2026.[9]

[9] The Irishtown Road project is identified as a future capital project in Appendix B.

## 3.6 Planning Capital Investments

Maritime Electric makes capital investments in the electrical system to ensure that, as required by Section 3(a) of the *Electric Power Act*, it is sustained in a condition that provides reliable service to customers and it has sufficient capacity to meet customer requirements as individual and overall system loads increase. When planning these investments, the Company must balance the need to replace system components, based on average service life expectations, and expand the system as new customers are added. Failure to achieve a proper balance can result in future system deficiencies that affect safety, reliability and cost. Considering the Company's size, Maritime Electric has an appropriate process for planning capital projects as described in this section of the Application and all capital projects planned for 2025 are considered necessary for the Company to meet its obligations as a public utility.

### a. Capital Planning Process

The Company's annual capital budget application outlines the projects, programs and activities that are necessary to meet system load requirements and provide safe and reliable service to customers. The items budgeted are required to: (i) connect new customers to the electrical system; (ii) replace equipment that has been damaged or failed as a result of storms or other causes; (iii) meet health, safety and environmental ("HSE") regulatory requirements; (iv) improve reliability; (v) provide security of supply; (vi) ensure system cybersecurity; (vii) strategically replace assets that have reached the end of their useful life; (viii) interact effectively with customers; and (ix) adapt to climate change.

The 2025 Capital Budget Application was based on the most recent information and analyses with respect to energy and load growth forecasts, asset inspection and monitoring data, electrical system reliability performance, operations and business technology requirements, and other factors that may impact the timing of capital projects in the near term. In addition, the Company's ISP and DAMP both guide the planning of projects to meet anticipated longer-term system and customer requirements.

The ISP identifies medium- and long-term system requirements based on a combination of historical system performance, load forecasting and professional engineering analysis, along with technological trends. For example, the ISP identifies major assets that need to be constructed or upgraded due to system load growth and/or age. The Lorne Valley switching station expansion project in Section 6.1b, herein, is an example of a load-growth-driven project, and the Sherbrooke X1 autotransformer replacement project in Section 6.1c, herein, is an example of a project that is driven by equipment age and condition.

Complementary to the ISP, the DAMP ensures that distribution assets are prudently and effectively managed to balance system reliability, cost and risk of failure. It helps to ensure that sufficient overall investment is being made to:

i. Provide for the growth needs of customers;
ii. Provide safe, reliable and high-quality service; and
iii. Satisfy the first two principles in a way that minimizes long-term costs.

Inherent in the DAMP is the determination of optimal asset management practices. Such practices can include the differentiation between a high volume of individually low-cost assets and a low volume of individually high-cost assets. For example, Maritime Electric has a high volume of poles and polemount transformers that are, individually, relatively low cost with a reasonably maintenance free service life (400,000 hours for poles and 300,000 hours for transformers). In addition, because pole and transformer failures often impact only a few customers, a replacement program that is based on an average annual replacement rate is acceptable.[10]

In contrast, Maritime Electric has a low volume of high-cost substation equipment that upon failure affects a large number of customers (e.g., substation power transformers, breakers and switches). Therefore, capital programs that include

[10] The DAMP recommends an average replacement rate of 850 transformers per year, based on approximately 34,000 transformers in service having an expected life of 40 years, and 2,600 wood poles per year, based on approximately 132,000 wood poles in service having an expected life of 50 years.

stocking critical spares, and monitoring of individually high-cost assets to detect problems and proactively address issues to avoid failure, is required.

The DAMP outlines the Company's general approach to identifying system needs for capital budget decision making; however, it is also important to note that dynamics outside of the Company's control can change project timing (in some cases with little or no advance notice). Examples of this include the addition of new commercial and large industrial customers, and the electrification of space heating which has significantly increased system load over the past several years. While the DAMP is specific to the distribution system, the generation and transmission assets are managed in a similar fashion and are also subject to the influence of external factors.

Supply chain is another external dynamic that has the potential to change project timing if delays are not anticipated in advance. Supply chain shortages have been experienced on a global scale by electrical utilities since the onset of the COVID-19 pandemic ("COVID-19") in early 2020 and are expected to continue into the foreseeable future as electrification and net-zero-driven energy policy is increasing industry-wide demand for electrical system equipment and materials. Maritime Electric has not been immune to this problem and has had to modify its capital planning, budgeting and procurement processes to address any delays that could impact new construction, system upgrades, asset replacement and the Company's ability to meet its obligations under the *Electric Power Act*. With capital planning and budgeting, some projects that in the past could be completed in one year, now require two or more years to complete, once approved. Substation power transformers in Section 6.1g is an example of such a change, as power transformer down payments are budgeted for year one and the balance budgeted for year two, due to delivery times now being approximately 24 months. Supply chain shortages also have an impact on procurement management, as consideration must be given to stocking critical spares and ordering extra inventory to have on hand in the event of a future supply disruption. This is more applicable to materials required for recurring capital work that is beyond the control of the Company, such as replacements due to road alterations, storm restoration, services and street lighting, and customer driven line extensions. To manage potential inventory deficiencies, the Company carefully monitors internal and supplier stock, and makes ordering decisions based on current information. In 2023, Maritime Electric modernized its inventory and supplier management systems to improve its ability to track and restock inventory in near-real time. However, when the Company cannot replace an out-of-stock item from suppliers within the timeframe that is required, other options, including loans from other Fortis Inc. ("Fortis") or neighbouring utilities, are pursued.

The development of a capital budget includes an assessment of the effectiveness and progress of existing activities, and the identification of new cost-effective activities that achieve reliability, provision of service and safety objectives, while responding to customer demands, load growth requirements and other system dynamics. A balanced capital budget will pursue these objectives while considering the long-term costs to be borne by customers. Maritime Electric has developed the 2025 Capital Budget Application to achieve a just and reasonable balance of system needs and the interests of customers.

In addition to the Company's process for planning and forecasting electrical system capital projects, there is also a need to invest in work support services to meet HSE regulatory requirements, communicate effectively with customers, provide functional and safe work facilities for employees, ensure a safe and reliable transportation fleet, and provide cyber secure information and operational technology solutions. The evidence provided in this Application explains how the need for capital investment is determined, and why the capital projects planned for 2025 are necessary.

**b. <u>Deferral in the Planning Process</u>**

The process of determining the projects required for 2025 also considered whether projects could be deferred to a later date. Projects that are required to: (i) connect new customers to the electrical system; (ii) replace equipment that failed as a result of storm damage or other causes; (iii) respond to load growth; or (iv) meet HSE regulatory requirements, typically, cannot be deferred. Projects to strategically replace assets that have reached the end of their useful life may, in theory, be deferred in the short term (i.e., one to two years).

The need to achieve an appropriate level of investment must be balanced against the overall risks associated with such deferrals. Therefore, annual capital expenditures are planned to avoid a long-term backlog of such capital projects; otherwise, the result would be an asset management program that is not achieving its sustainable objective.

As indicated, capital projects to strategically replace assets that have reached the end of their useful life may, in theory, be deferred in the short term. An example is the replacement of a distribution line that is aged and deteriorated. Such a project should only be deferred in the short term as a longer-term deferral runs the risk of multiple failures of that asset prior to replacement, resulting in unnecessary customer outages or an unsafe situation. Also, the replacement of failed assets is typically more expensive (e.g., when overtime is required) than a planned replacement. Always deferring to failure would be in direct contradiction to the Company's objective to provide reliable service at the least cost. Examples of capital projects that were identified in previous years but deferred until 2025 are provided in Table 9, and examples of capital projects originally planned for 2025 that have been deferred to subsequent years are provided in Table 10.

| TABLE 9<br>2025 Capital Projects Deferred from Previous Years | |
|---|---|
| **Project** | **Description** |
| Blue Shank Road Three Phase Conversion | The Blue Shank Road three phase conversion project, as described in Section 5.4b, herein, was initially identified as a 2024 capital project in the 2022 Capital Budget Application. This was changed in the 2023 Capital Budget Application with the project being deferred to 2025. The primary reason for the deferral was a more pressing need to complete the Pleasant Grove Road three phase conversion in 2024. |
| West Royalty X4 Power Transformer | The West Royalty substation X4 power transformer replacement project was previously identified as a 2024 capital project in the 2022 and 2023 Capital Budget Applications. This was changed in the 2024 Capital Budget Application with the project being deferred to 2025, for inclusion in the West Royalty substation 13.8 kV distribution replacements projects, as described in Section 6.1d, herein. |

| TABLE 10<br>Capital Projects Deferred from 2025 to Subsequent Years | |
|---|---|
| **Project** | **Description** |
| T-1 Reroute | A project to rebuild and reroute transmission line T-1 over a three-year period, beginning in 2025, was initially included in the future capital projects list of the 2023 Capital Budget Application. This project was deferred to 2027 in the 2024 Capital Budget Application and has subsequently been deferred to begin in 2029. This deferral has been necessary to accommodate the earlier-than-anticipated requirement to expand the Lorne Valley switching station to 138 kV, rebuild Scotchfort substation, and complete related 138 kV transmission projects. |
| Communication Fibre – Scotchfort to Lorne Valley | A project to run communication fibre from Scotchfort to Lorne Valley in 2025 was identified in the future projects list of the 2024 Capital Budget Application. It has been deferred to 2026 to better align with the completion of Y-106 and the Lorne Valley switching station expansion. Conversely, a project to run communication fibre from Church Road to Souris was moved from 2026 to 2025, to provide the Energy Control Centre (“ECC”) and Backup Control Centre (“BCC”) with improved remote visibility and control options for the Souris substation. |

Capital projects are scheduled to address known or anticipated issues related to age, condition, safety, capacity, and reliability. While the Company endeavors to provide the most accurate forecast of future capital projects, unforeseen issues can arise causing the timing of projects to change, new projects to be added, and in some cases, significant change to the scope of projects. As such, the List of Future Capital Projects, provided in Appendix B, is based on current information. Changing information may result in a project being advanced to an earlier year, deferred to a later year, or removed entirely. Examples of new information that could result in the deferral or removal of a project include:

i. Updated customer, energy and demand forecast. A reduced forecast could result in the deferral of a planned substation or distribution upgrade;
ii. Updated condition assessments of equipment. A piece of equipment that is aged but inspected and found to be in adequate condition could result in the deferral of a refurbishment or replacement project; and
iii. Updated assessments of potential customer benefits. Changes in system costs or technologies may result in a project no longer being economic for customers, allowing the project to be deferred or eliminated.

The Company considers all available information in evaluating alternatives for meeting a particular system requirement. This can include solutions that do not require capital investments, such as transferring customer load to an adjacent substation when overload conditions arise. It can also include small capital investments to delay the full replacement of the asset, such as the replacement of component parts (e.g., switches) when reasonably practical. Each of these factors can result in the deferral of a project.

While the deferral of capital projects can and do occur, it must be recognized that the prolonged deferral of a project required to upgrade or replace the system components can result in assets being unsafe for the public and Company employees, lead to more frequent outage events (especially during storm situations) and increase costs because it is often more time consuming to safely work on (or around) deteriorated assets. Similarly, the prolonged deferral of capital projects that are driven by load growth can lead to outages at times of high demand, low voltage situations that can damage customer assets (resulting in damage claims), and be harmful to critical equipment. Good utility practice requires consideration of all these factors to develop and implement sustainable levels of annual capital investment.

During the process of preparing the Application, a comprehensive assessment of all proposed capital projects was completed and only projects that could not be deferred have been included.

**c. <u>Capital Cost Accounting</u>**

Maritime Electric follows Canadian private entity Generally Accepted Accounting Principles ("GAAP"), which allows reference to other guidance including accounting principles established in the United States ("US"). In the US, the Federal Energy Regulatory Commission ("FERC"), which regulates the transmission and wholesale sale of electricity, developed a Uniform System of Accounts ("USofA") for the financial accounting of regulated utilities. Following the FERC USofA is considered good utility practice in Canada. According to FERC, to capitalize costs associated with an existing asset owned by the Company, the costs must meet the following two qualifications:

1. Extend the life, increase the capacity, or improve the safety or efficiency of that asset; and
2. Improve the condition of that asset after the costs are incurred, as compared with the condition of that asset when originally constructed or acquired.

<u>Capitalization Policy</u>

Maritime Electric's capitalization policy is documented in pages 6 to 21 of the Company's Accounting Manual, provided in Appendix G. This section of the Accounting Manual includes detailed information on the account classification of all property, plant and equipment ("PPE") for the Company. The manual is designed to follow specifications and instructions of FERC documented in Electric Plant Instructions, provided as Appendix H, and Electric Plant Accounts, provided as Appendix I. In following FERC protocols, the Electric Plant Instructions and Electric Plant Accounts documents are used to determine what items are included and properly charged to an account.

In the US, public electrical utilities and licensees are required to maintain their books and records in accordance with FERC specifications and instructions. In Canada, while it is not a requirement, it is considered good utility practice to do so.

PPE are assets that are expected to have an economic useful service life beyond one year. Expenditures made to service PPE are capitalized when the expenditure provides a betterment to the asset and its service life is extended beyond its original expected service life. Once a PPE asset reaches the end of its useful service life, it is retired from service and the associated costs of removing the asset are charged to retirement.

All expenditures associated with development, engineering, acquisition or construction of the assets are accumulated and recorded as the cost of the asset when placed into service. Examples of cost include:

- Design, engineering and consulting;
- Internal labour and transportation;
- Contractor labour;
- Materials:
  - Materials purchased or constructed (i.e., transformers, substations, generating plants); and
  - Materials supplied by Maritime Electric Stores inventory (i.e., poles, conductor, line hardware and control devices);
- Legal and professional services; and
- Other directly attributable expenditures (i.e., travel, accommodations, meals).

When major adverse events or damage caused by weather, natural disasters, accidents or emergencies occur and require immediate restoration response, the Company capitalizes the installation of new equipment and certain vegetation management costs that are necessary to access the installation site. The Company measures the installation costs as the actual cost of the materials plus an allocation of labour. The labour allocation is based on historical experience installing similar equipment adjusted for emergency labour rate premium, travel and other costs.

Critical Spares

The overall management of the electrical system also includes the identification of critical components that upon failure would affect many customers. If these components are difficult to source or have a significant delivery time, it is considered prudent to secure critical spares.

Under the "used and useful" concept, only system equipment (or plant) that is currently providing or capable of providing utility service to customers is to be included in rate base. However, maintaining critical spares is an essential component of the requirement to provide least cost, reliable service. To address this need, FERC and most regulators allow "plant held for future use" to also be included in rate base provided there is a definite plan for its use (i.e., it is intended for a very specific and essential purpose). This approach is consistent with recognized accounting standards as indicated below.

According to Chartered Professional Accountants Canada Handbook, Part II - Accounting Standards for Private Enterprises ("ASPE"), Section 3061.03:

> *"Spare parts and servicing equipment are usually carried as inventory and recognized in net income as consumed. However, major spare parts and standby equipment qualify as property, plant and equipment when an entity expects to use them during more than one period. Similarly, if the spare parts and servicing equipment can only be used in connection with an item of property, plant and equipment, they are accounted for as property, plant and equipment."*

International Accounting Standard ("IAS"), IAS16, paragraph 8 includes the following discussion:

> *"Spare parts and servicing equipment are usually carried as inventory and recognized in profit or loss as consumed. However, major spare parts and stand-by equipment qualify as property, plant and equipment when an entity expects to use them during more than one period. Similarly, if the spare parts and servicing equipment can be used only in connection with an item of property, plant and equipment, they are accounted for as property, plant and equipment.*
>
> *For rate-making and reporting purposes, in most cases major spare parts and stand-by equipment (e.g., transformers and meters) should be accounted for as property, plant and equipment capital assets, as it is expected that:*
>
> *a. these items are not held for sale in the ordinary course of business or to be consumed in the production process or rendering of services;*
> *b. they have a longer period of future economic benefit as compared to inventory items;*
> *c. they form an integral part of the original distribution plant by enhancing the system reliability of the original distribution plant; and*
> *d. they embody future economic benefits because they are expected to be placed in service."*

Based on the above, Maritime Electric considers investment in critical spares as part of the capital planning process and, as such, these capital assets are properly included in rate base.

## 3.7 Budget Components and Process

Maritime Electric's capitalization policy determines what qualifies as a capital expenditure, and the type and scope of each capital project or program proposed by the Company determines the relative balance of materials and equipment, external labour, internal labour and transportation, and other resources that are required to complete the work.[11] An overview of these budget components, including how they are incorporated into the estimating process is provided as follows.

### a. Materials and Equipment

Maritime Electric typically procures materials and equipment for capital projects and programs through competitively sourced standing offer material supply contracts, or job-specific material and equipment tenders. The Company has also benefitted from its affiliation with other Fortis companies. For example, in the past, the group purchasing of poles with Newfoundland Power resulted in a lower price than the Company could have secured on its own. The Company also participates in Fortis group tendering for transformers but purchases directly from the chosen supplier at the tendered prices.

Materials for capital projects and programs are incorporated into proposed budget amounts using the unit cost of each specific item that has been entered into the Company's financial inventory system, which is based on competitively sourced or standing offer pricing.

### b. External Labour

Maritime Electric engages external consultants and contractors to perform work that the Company does not have sufficient internal labour resources to perform or, in some instances, the necessary experience, expertise or equipment to do the work safely. The specifics of each capital project or program in this Application dictates whether external labour is required.

[11] A capital project is typically associated with a specific undertaking with activities in a defined location and a completion timeframe of less than a year (although some larger projects can be multi-year). A capital program is typically designed to address a specific issue at multiple locations over a period of several years.

Contractor labour is typically sourced locally through fixed-term agreements (one-year or multi-year contracts) or a competitive bidding process. Fixed-term agreements are more applicable to distribution and transmission line projects involving line crews, vegetation management crews and traffic control crews. Such agreements establish hourly contractor rates that apply to planned work as well as unplanned system events that require external resources (e.g., storm response). Like internal labour, hourly rates for contractor labour typically include a transportation cost component. An example of a fixed-term agreement for vegetation management services is provided in Confidential Appendix Q-2.

A competitive bidding process is used where fixed-term agreements are not in place. A competitive bidding process is sometimes used even where a fixed-term agreement is in place to check that the rates specified in the fixed-term agreement are reasonably competitive. An example of a past call for tender and associated bid submissions for vegetation control work is provided in Confidential Appendix Q-3.

**c. <u>Internal Labour and Transportation</u>**

Maritime Electric generally constructs, monitors and services its own assets and, as such, most capital project and program cost estimates include an internal labour component. Furthermore, because the nature of the work and the disbursement of assets across the Island requires access to a fleet of vehicles to perform this work, the internal labour cost includes associated transportation costs.

<u>Internal Labour</u>

The Company's capital investment is based on a least cost approach with internal labour mainly provided by a unionized workforce under a Collective Agreement with Local 1928 of the International Brotherhood of Electrical Workers. Internal labour also includes non-union positions typically for planning, engineering support, project management, field supervision and administration. The Collective Agreement establishes the negotiated hourly rates of the unionized workforce for regular, overtime and double-time work. Salaries for non-union positions are determined using a structured Korn-Ferry process that reflects job functions and comparable employment in the region. Therefore, internal labour costs are supported by either a negotiated Collective Agreement or comparison to regional benchmarks.

Transportation

The Company operates five classes of vehicles in its fleet: (i) passenger vehicles; (ii) pickup trucks; (iii) vans; (iv) 1-to-3-ton trucks; and (v) trucks over 3 tons. The cost to operate these vehicles includes fuel, insurance, registration, maintenance, parking, washing and lease costs (when applicable). For budgeting, an hourly rate for each class of vehicle is calculated based on the total operating costs for the previous year. Vehicles are assigned to employees by the type required and the hourly vehicle rate is combined with the employee hourly rate resulting in an internal labour and transportation rate for that employee position.

Standard Distribution of Costs

For each capital project or program proposed in this Application, a total cost of internal labour and transportation is provided. Maritime Electric budgets internal labour and transportation costs to the appropriate accounts based on the planned capital and operating activities for the budgeted year (i.e., standard distribution based on planned activities). For recurring capital activities, this budget considers actual expenditures in recent years and any changes that may be necessary due to other factors. For non-recurring capital activities, the internal labour and transportation budget is set based on an estimate of the type and quantity of resources required to complete the work. In the case of both recurring and non-recurring capital activities, when allocating internal labour and transportation the budget is either assigned to a single project or, for efficiency, it is assigned to a group of projects or a program. In the Application, an example of the former is the Section 4.1b ECC Mechanical Upgrades and Electrical Assessment project, which assigns internal labour and transportation to a specific project, and an example of the latter is the Section 6.1i Substation Modernization Program, which assigns internal labour and transportation for all items in the program.

Once budgets are approved, actual costs are reviewed monthly and compared to budget. If the standard distribution allocation of actual internal labour and transportation costs to capital and operating accounts does not accurately reflect the work completed, the allocation of internal labour and transportation costs is adjusted. This review and adjustment ensure the allocation of internal labour and transportation costs is reasonably accurate.

The standard distribution of labour and transportation costs is reviewed and updated annually to ensure that it accurately allocates costs to the appropriate accounts based on the planned capital and operating activities for that year. If actual activities differ significantly from what was planned, the standard distribution allocations are updated accordingly. The use of standard distribution is a cost-effective approach that results in an appropriate allocation of labour and transportation to operating and capital activities.

On a related note, while the Company does not use a time tracking approach for regular day-to-day work, it does use an exception timesheet system to record internal labour and transportation associated with system events, specific projects and overtime, as necessary. For example, exception timesheets were used during the Fiona response to record associated internal labour and transportation costs to a storm-specific account. Exception timesheets are also used when Company crews are assigned to specific capital projects (e.g., line extensions, line rebuilds, etc.), when work is being completed for, and billed to, a third party (e.g., joint-use make-ready projects), and when system repair and replacements costs can be recovered through insurance (e.g., damages resulting from a vehicle accident). This approach ensures costs are appropriately charged to the projects as they occur.

**d. <u>Estimating Capital Expenditures</u>**

Capital projects tend to be localized to a community level with durations measured in weeks or months (e.g., rebuilds and line extensions). Capital programs typically address the upgrading or replacement of equipment, parts and tools on an as required provisional basis, or specific system issues that require a longer term and Island-wide approach to effectively monitor, maintain and/or replace capital assets (e.g., substation modernization, distribution line refurbishment, eastern cedar pole and deteriorated conductor replacement, backlot feed relocations, etc.).

Maritime Electric incorporates a variety of methods to estimate proposed capital expenditures. An overview of how the Company typically estimates budgets for line construction and asset replacement activities is provided below.

Capital projects tend to require a more detailed consideration of costs that cannot be reasonably estimated using broad assumptions. For example, a kilometre ("km") of three phase line construction can vary considerably by location due to variations in work methods and/or the extent of requirements for traffic control, vegetation clearing, travel time, etc. This being the case, the Company estimates project costs based upon the labour, material, equipment and other resource requirements, as well as consideration of job-specific factors. The job-specific factors for each line construction project proposed in this application are outlined in the project descriptions provided in Appendices J, K and N.

For capital programs, recent historical data is often adequate to estimate unit costs that can be extrapolated to quantify the program scope (e.g., the number of eastern cedar poles replaced within budget allocations of previous years). Use of historical cost data is more applicable to capital programs that span several years than it is to customer or event-driven provisional allocations (e.g., storm response, system modifications due to road alterations, new service connections, etc.).

As outlined above, distribution and transmission line construction projects are estimated on a job-by-job basis to ensure that the proposed budget allocation is as accurate as possible. Material estimates are prepared using the Company's survey system which has an integrated material database that is updated regularly.[12] The estimating process involves, but is not limited to, the following steps and considerations:

Project Definition

- Project scoping with input from Maritime Electric professional engineering staff and the district manager where the project will be located;
- Determination if the line extension or rebuild will be constructed on the same side or opposite side of the road relative to the existing line;
- Identification of any environmental restrictions or special considerations that will affect the project;
- Selection of conductor type based on current and future load requirements;
- Determination of joint-use status and scope conversion requirements, if applicable; and
- Determination of pole span requirements based on the selected conductor and the joint-use requirements.

Construction Cost Factors

- Pole height and hardware requirements are based on line type, right-of-way topography, roadway clearances and space for joint-use attachments, if applicable;
- Quantity and height of tangent pole, single pin turn, double pin turn, running angle turn and double dead-end corner structures;
- Amount of conductor and neutral wire required, allowing for sag;
- Number of primary service take offs to customer premises, and related quantity of primary wire and cutouts;
- Number of transformers to be removed/installed and associated requirements for secondary wire;
- Number of street lights that need to be removed/installed; and

[12] The survey system is an in-house developed software application that is used to assign survey work, track its status, specify material and labour requirements, estimate costs, and prepare jobs for assignment to line crews and technicians.

- Requirements for traffic control, vegetation clearing, special pole supports (culvert and gravel), portable washrooms, job trailers, snow removal from ditches, equipment rental, lodging crews, etc.

An estimate template is used in conjunction with the survey system, which allows the incorporation of job- and site-specific factors that can impact the overall project cost. This may involve applying contingency amounts to the labour components of the job. Also, as already noted, heavy vegetation, high speed or high-volume traffic, and requirements for hot-line work are examples of job- and site-specific factors that can cause similar sized jobs in different locations to vary considerably in cost.

<u>Inflation and Supply Chain Considerations</u>
Historically, annual adjustments for inflation in Maritime Electric's capital budget applications have typically been in the 2 to 3 per cent range. This has usually been adequate to cover increases in external and internal labour rates, which tend to be across the board, and increases in equipment and material costs, which can vary but tend to average out.

In recent years, during and since the COVID-19 pandemic, Maritime Electric has experienced above normal inflation and supply chain delays on some equipment and materials that it relies upon to operate the electrical system. Increased capital expenditures due to inflation have led to over-budget variances on some projects, and supply chain delays have led to capital budget carryovers being required. Both of these issues now appear to be stabilizing; however, demand for electrical equipment due to electrification and the energy transition throughout the industry is increasing and could lead to new challenges in terms of cost and availability for equipment and materials in the foreseeable future.

As such, inflation and supply chain delays could impact the projects and programs proposed in the 2025 Capital Budget Application; however, to the extent possible, the proposed expenditures and project completion timelines indicated in the

Application are current and realistic in terms of labour, equipment, and material cost, as well as resource/product availability.

Contingencies

Contingency amounts are included in some cost estimates to allow for unforeseen costs associated with project uncertainties. Cost uncertainties are common in unique or complex projects as well as when the timeframe between estimating and incurring costs is protracted.

Contingency amounts are determined based on the estimator's judgement/experience, the level of project definition (i.e., percentage of detailed engineering completed) at the time the cost estimate was prepared, the number of potential bidders for a project (i.e., sole source projects often require higher contingencies), and the complexity of the project. When setting contingency amounts, Maritime Electric compares historical project costs to budgeted project costs and adjusts contingency amounts accordingly.

Maritime Electric cost estimates often include contingencies similar to those published in the American Association of Cost Estimating ("AACE") International's Recommended Practice 18R-97, as shown in Table 11. With this cost estimating methodology, contingencies vary based on the class of cost estimate prepared.
Generation projects tend to include contingency amounts because they are often unique projects compared to Distribution, Transmission and Corporate projects. Contingency allocations are often not budgeted for capital programs, line construction and corporate projects, as they tend to be similar from year to year and the estimator has actual expenditures from previous years to base the estimate upon. However, exceptions are required when the projects are complex (e.g., energized rebuild work or the development of a customized software application), when civil works are involved (e.g., construction of substations and other facilities) and when pricing from prior years is used for budgeting but is reasonably expected that there will be a material cost increase when the item is ordered. In the case of complex projects and projects involving civil work, budgets

are typically estimated to an AACE Class 2 or Class 3 level with contingencies in the 5 to 30 per cent range. In the case of item-specific cost increases that are reasonably expected, contingencies are set based on industry indices or costs for purchasing similar materials or equipment.

**TABLE 11**
**AACE International's Recommended Practice for Cost Estimating**

| | *Primary Characteristic* | *Secondary Characteristic* | | | |
|---|---|---|---|---|---|
| **ESTIMATE CLASS** | **LEVEL OF PROJECT DEFINITION** Expressed as % of complete definition | **END USAGE** Typical purpose of estimate | **METHODOLOGY** Typical estimating method | **EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a] | **PREPARATION EFFORT** Typical degree of effort relative to least cost index of 1 [b] |
| **Class 5** | 0% to 2% | Concept Screening | Capacity Factored, Parametric Models, Judgment, or Analogy | L: -20% to -50%<br>H: +30% to +100% | 1 |
| **Class 4** | 1% to 15% | Study or Feasibility | Equipment Factored or Parametric Models | L: -15% to -30%<br>H: +20% to +50% | 2 to 4 |
| **Class 3** | 10% to 40% | Budget, Authorization, or Control | Semi-Detailed Unit Costs with Assembly Level Line Items | L: -10% to -20%<br>H: +10% to +30% | 3 to 10 |
| **Class 2** | 30% to 70% | Control or Bid/ Tender | Detailed Unit Cost with Forced Detailed Take-Off | L: -5% to -15%<br>H: +5% to +20% | 4 to 20 |
| **Class 1** | 50% to 100% | Check Estimate or Bid/Tender | Detailed Unit Cost with Detailed Take-Off | L: -3% to -10%<br>H: +3% to +15% | 5 to 100 |

Notes: [a] The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.
[b] If the range index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

## 4.0 GENERATION $1,137,000

Maritime Electric's two on-Island generating stations, which are primarily backup supply sources, are equipped as follows:

| | | |
|---|---|---|
| Borden Generating Station ("BGS") | 2 Generators | 40 MW (total) |
| Charlottetown Generating Station ("CGS") | 1 Generator | 50 MW |

The BGS is the site where Combustion Turbine 1 ("CT1") and Combustion Turbine 2 ("CT2") are located. The CGS is the site where Combustion Turbine 3 ("CT3") is located. The primary role of Maritime Electric's on-Island generation is to supply energy in times of curtailment from off-Island energy suppliers, or during transmission line outages or curtailments on either PEI or the mainland. Other benefits of having on-Island generation include reduced purchased capacity costs and the ability to provide backup for the four submarine cables connecting PEI to the mainland.[13]

The Generation component of the Capital Budget is comprised of projects required to maintain the generating stations in a state that enables the Company to meet reliability and safety requirements. These requirements are 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.

### 4.1 Charlottetown Generating Station - Buildings and Site Services *$ 271,000*

This category includes CGS expenditures required for buildings and site services projects, which includes necessary refurbishments, replacements and upgrades to the ECC, BCC, and to infrastructure within the CGS site.

The ECC provides continuous 24-hour monitoring and operation of Maritime Electric's electrical system by performing functions such as energy purchases, load and wind

[13] Having dispatchable on-Island generation enables Maritime Electric to purchase interruptible energy which is less costly than non-interruptible (or "firm") energy. Also, it puts an upper limit on the cost of purchased energy (i.e., when the price is too high, the energy can be produced by running the on-Island generation).

forecasting, generation dispatch and line crew dispatch. The ECC building, located on Cumberland Street in Charlottetown, was constructed in 1976. The BCC, located at West Royalty Service Centre (“WRSC”), is equipped to serve as the control centre for Company operations if the ECC is not available for any reason. The BCC can also be used concurrently with the ECC to segregate operators into cohorts in accordance with the Company’s pandemic response operational plan.

The CGS site encompasses the following infrastructure inside the fence line at the Cumberland Street site: ECC building; 69 kilovolt (“kV”) Charlottetown Plant substation; substation control building; 69 kV capacitor bank; 50 MW CT3 and CT3 building; X4 step-up power transformer and auxiliaries; fuel storage, containment and offloading facility; machine shop; and storage building.

A breakdown of the historical expenditures, 2024 budget and the proposed 2025 budget for CGS buildings and site service projects is shown in Table 12.

**TABLE 12**
**Historical and Proposed Expenditures**
**CGS Buildings and Site Services[a]**

| Description | 2020 [b] | 2021[c] | 2022[d] | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material and External Labour | $ 287,578 | $ 158,374 | $ 22,228 | $ 63,805 | $ 310,000 | $ 209,000 |
| Internal Labour and Transportation | 6,639 | 6,612 | 6,796 | 17,238 | 37,000 | 62,000 |
| Other | 2,238 | 5,935 | - | 1,020 | - | - |
| **TOTAL** | **$ 296,455** | **$ 170,921** | **$ 29,024** | **$ 82,063** | **$ 347,000** | **$ 271,000** |

a Prior to 2022, the equivalent Generation subcategory was identified as Charlottetown Plant Buildings and Services Projects.
b. Includes $26,538 for 2020 projects carried over and completed in 2021.
c. Includes $64,667 for 2021 projects carried over and completed in 2022.
d. Includes $17,051 for 2022 projects carried over and completed in 2023.

a. **CGS Miscellaneous Building and Site Upgrades (Recurring) $ 52,000**

As CGS buildings and site services age, upgrades are required each year to address deteriorated components. Experience indicates that unplanned and emergency events will also occur that require capital replacements, refurbishments and upgrades. Performing necessary replacement, refurbishment and upgrade work in a timely manner, when the need arises, helps to ensure that CGS facilities remain in adequate condition for the safety of employees and to avoid costly emergency repairs or replacements.

As the projects under this budget category are unplanned and identified on an as-required basis, cost projections at the item level cannot be determined in advance and, therefore, the proposed budget is provisional.

***Justification***

The proposed provisional budget is justified on the obligation to ensure the efficient and safe operation and use of CGS facilities. For this reason, when projects arise throughout the year, they cannot be deferred.

***Costing Methodology***

A breakdown of the historical expenditures, 2024 budget and the proposed 2025 budget for CGS miscellaneous building and site upgrades is shown in Table 13.[14]

[14] The 2025 budget amount in Table 13 is based on a five-year average of actual and budgeted expenditures, from 2020 to 2024, that were normalized to 2025 dollars using an annual escalation rate of 3 per cent.

| TABLE 13<br>Historical and Proposed Expenditures<br>CGS Miscellaneous Building and Site Upgrades | | | | | | |
|---|---|---|---|---|---|---|
| **Description** | **2020[a,b]** | **2021[c, d]** | **2022** | **2023** | **2024 Budget** | **2025 Budget** |
| Material and External Labour | $ 112,642 | $ 23,294 | $ 7,228 | $ 30,589 | $ 21,000 | $ 45,000[e] |
| Internal Labour and Transportation | 5,790 | 1,120 | 1,384 | 9,632 | 16,000 | 7,000 |
| Other | 4,781 | 435 | - | 1,020 | - | - |
| **TOTAL** | **$ 123,213** | **$ 24,849** | **$ 8,612** | **$ 41,241** | **$ 37,000** | **$ 52,000** |

a. In the 2020 Capital Budget, the equivalent item was under 4.1c Charlottetown Plant Miscellaneous Buildings and Services and prior to 2019, there was no equivalent item (i.e., it was consolidated with all Charlottetown Plant Buildings and Services Projects).
b. Includes $26,538 for 2020 projects carried over and completed in 2021.
c. In the 2021 Capital Budget, the equivalent budget allocation is listed as item iii in Table 9 of Section 4.1a.
d. Includes $3,197 for 2021 projects carried over and completed in 2022.
e. Includes the five-year average amount for “Other” expenditures.

To ensure projects are completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for the project is January 2025 with completion dates throughout the year.

***Alternatives***

Alternatives will be considered at the time when CGS miscellaneous building and site upgrades are identified, as required.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring provisional capital requirement that is budgeted annually.

**b. <u>ECC Mechanical Upgrades and Electrical Assessment</u>**
**(Justifiable) $ 151,000**

This project includes the replacement of a roof heating, ventilation and air conditioning ("HVAC") unit with an HVAC heat pump, the modification of a bathroom into a shower facility in the ECC building, and an electrical engineering assessment of the ECC building's electrical system.

The ECC building's HVAC unit is a 2008 model and will be 17 years old in 2025. It is due to be replaced with a more efficient heat pump HVAC unit that can be interchanged with the old unit. The service life of HVAC systems generally range from 15 to 20 years.

Given the importance of ECC's continuous 24-hour monitoring and operation of the PEI electrical grid, in the event of a storm or system event, employees may be required or constrained from leaving the workplace and must stay onsite. Currently there is no shower facility in the ECC building for employees to use when they cannot leave the building.

The ECC building's electrical system requires upgrades to modernize it and increase its capability to maintain and support additional infrastructure. An electrical engineering assessment of the ECC building will provide a professional engineer's plan to upgrade the ECC building's electrical system to meet the future needs of the facility.

***Justification***

The proposed ECC mechanical upgrades and electrical assessment are justified on the need to ensure that the ECC building has a HVAC system, and modern electrical infrastructure to support the facility's function. Additionally, the upgrades give employees stationed at the ECC building the facilities required if they are either required or constrained to the ECC building during storms or system events.

***Costing Methodology***

The proposed budget is based on a combination of vendor quotations for material and external labour, and professional engineering estimates for internal labour and transportation.

A breakdown of the proposed budget for the ECC mechanical upgrades and electrical assessment project is shown in Table 14. A contingency has been budgeted as the upgrades are one-off projects, vendor quotations may need to be refreshed, some component costs were estimated, and to accommodate minor adjustments in scope of supply that are commonly required with this type of work.

**TABLE 14**
**Breakdown of Proposed Budget**
**ECC Mechanical Upgrades and Electrical Assessment**

| Description | Budget |
|---|---|
| Material and External Labour | $ 84,000 |
| Internal Labour and Transportation | 47,000 |
| Contingency (15 per cent) | 20,000 |
| **TOTAL** | **$ 151,000** |

Supporting information for the cost estimates included in Table 14 is provided in Confidential Appendix Q-4.

To ensure this project is completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for the project is January 2025.

***Alternatives***

There is no alternative to replacing the HVAC unit, extending the current unit beyond its typical service life could risk the unit failing and disrupting ECC facility operations.

There is no alternative to installing a shower in the ECC building. Installing a shower will provide ECC employees with the necessary facilities to stay on site, if necessary, during storms or system events.

There is also no alternative to foregoing the ECC building electrical assessment. The ECC building is the main control centre for the monitoring and operation of the PEI electrical grid. As technology and infrastructure throughout the Company changes, the ECC building's electrical capability must be improved to adequately support these new systems. The first step in improving the building's electrical system is to understand the current system and plan for upgrades.

***Future Commitments***

This is not a multi-year capital budget commitment; however, the ECC building electrical assessment may identify upgrade work to be completed in 2026.

**c. <u>CGS Entrance Improvements and Modifications</u> (Justifiable) $ 68,000**

This project involves improvements and modifications to the entrance roadway of the CGS facility accessing Cumberland Street.

The current Cumberland Street entrance is an extension of Richmond Street. The entrance road, which is currently owned by the City of Charlottetown, is being transferred to Maritime Electric ownership at zero cost.[15] This entrance has been in disrepair for some time and needs to be rebuilt. In addition, the current security gate and fence will be modified and moved closer to Cumberland Street. This will

[15] Maritime Electric has agreed to transfer a parcel of land of equivalent size and value to the City of Charlottetown that is required for the Eastern Gateway Project.

create more room within the CGS facility and eliminate the need for some security fencing.

***Justification***

The entrance improvements are justified based on ensuring a functioning and safe roadway for accessing the CGS facility. The modifications to the security fence are justified based on being able to reclaim useful space within the CGS facility once the old fencing is removed.

***Costing Methodology***

The proposed budget is based on a combination of vendor quotations for material and external labour, and professional engineering estimates for internal labour and transportation.

A breakdown of the proposed budget for the CGS entrance improvements and modifications project is shown in Table 15. A contingency has been budgeted as this is a one-off project, the vendor quotation may need to be refreshed, some project component costs were estimated, and to accommodate minor adjustments in scope of supply that are commonly required with this type of project.

**TABLE 15**
**Breakdown of Proposed Budget**
**CGS Entrance Improvements and Modifications**

| Description | Budget |
|---|---|
| Material and External Labour | $ 51,000 |
| Internal Labour and Transportation | 8,000 |
| Contingency (15 per cent) | 9,000 |
| **TOTAL** | **$ 68,000** |

Supporting information for the cost estimates included in Table 15 is provided in Confidential Appendix Q-4.

To ensure this project is completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for the project is the spring of 2025.

***Alternatives***

An alternative to rebuilding the roadway entrance to the CGS facility is to patch the numerous potholes and an alternative to replacing the security fence and gate would be to delay this until another time. Neither of these modifications/deferrals will achieve the site access and functionality improvements that will be gained through the project, as planned.

***Future Commitments***

This is not a multi-year capital budget commitment.

## 4.2 Charlottetown Generating Station – Turbine Generator *$ 438,000*

This category includes expenditures associated with the generation equipment located at the CGS, which includes CT3 and ancillary systems.

The CT3 ancillary systems include the following: ventilation and combustion air system; lube oil system; instrument air system; liquid fuel system; fire protection system; generator excitation system; vibration monitoring system; and other miscellaneous components.

The capital projects proposed in this category are critical to ensuring CT3 is in a state that it is ready to operate on demand.

A breakdown of the historical expenditures, 2024 budget and the proposed 2025 budget for CGS turbine generator projects is shown in Table 16.

| TABLE 16<br>Historical and Proposed Expenditures<br>Charlottetown Generating Station - Turbine Generator[a] | | | | | | |
|---|---|---|---|---|---|---|
| **Description** | **2020[b]** | **2021[c]** | **2022[d]** | **2023** | **2024 Budget** | **2025 Budget** |
| Material and External Labour | $ 170,936 | $ 494,078 | $ 319,662 | $ 297,587 | $ 165,000 | $ 409,000 |
| Internal Labour and Transportation | 4,578 | 213,551 | 95,614 | 53,884 | 16,000 | 29,000 |
| Other | 2,658 | 15,625 | 163,263 | 2,149 | - | - |
| **TOTAL** | **$ 178,172** | **$ 723,254** | **$ 578,539** | **$ 353,620** | **$ 181,000** | **$ 438,000** |

a. Prior to 2022 the equivalent Generation category was identified as Charlottetown Plant Turbine-Generator Projects.
b. Includes $10,067 for 2020 projects carried over and completed in 2021.
c. Includes $40,423 for a 2021 project carried over and completed in 2022.
d. Includes $151,357 for a 2022 project carried over and completed in 2023.

**a. CGS Combustion Turbine Improvements, Parts and Tools (Recurring) $ 180,000**

The proposed budget is for the supply and installation of replacement equipment, critical parts and tools as required for the continued safe and reliable operation of the CT3 unit.

As the projects under this budget category are unplanned and identified on an as-required basis, cost projections at the item level cannot be determined in advance and, therefore, the proposed budget is provisional.

***Justification***

This project is justified based on the obligation of a public utility, under the *Electric Power Act*, to provide reasonably safe and adequate service, which requires the Company to manage all supply resources. The availability of CT3 to operate when needed is of critical importance to security of supply.

### *Costing Methodology*

The proposed provisional budget was estimated based on historical expenditures for equipment replacements due to in-service failures. A breakdown of the historical expenditures, 2024 budget and proposed 2025 budget for CGS combustion turbine improvements, parts and tools is shown in Table 17.[16]

**TABLE 17**
**Historical and Proposed Capital Expenditures**
**CGS Combustion Turbine Improvements, Parts and Tools**

| Description | 2020[a] | 2021 | 2022 | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material and External Labour | $ 70,267 | $ 134,166 | $ 147,466 | $ 206,098 | $ 165,000 | $ 160,000[b] |
| Internal Labour and Transportation | 4,578 | 14,794 | 26,099 | 32,654 | 16,000 | 20,000 |
| Other | 2,658 | 8,991 | 2,355 | - | - | - |
| **TOTAL** | **$ 77,503** | **$ 157,951** | **$ 175,920** | **$ 238,752** | **$ 181,000** | **$ 180,000** |

a. The 2020 budget was reduced from historical levels due to the proposed CT3 Equipment Building Project.
b. Includes the five-year average amount for "Other" expenditures.

To ensure this project is completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for this project is January 2025 with in-service dates throughout the year, as required.

### *Alternatives*

There is no alternative to this project. CT3 provides critical on-Island backup generation capability and the consequence of not having readily available funds to

[16] The 2025 budget amount in Table 17 is based on a five-year average of actual and budgeted expenditures, from 2020 to 2024, that were normalized to 2025 dollars using an annual escalation rate of 3 per cent.

enable the acquisition of critical parts or replacements due to unforeseen in-service failure, could result in the equipment not being available for operation when required.

***Future Commitments***

This is not a multi-year capital budget commitment, but it is a recurring provisional capital requirement that is budgeted annually.

**b. <u>CT3 Spare and Replacement Parts</u> $ 258,000**

This project involves purchasing four spare station service circuit breakers and one replacement air compressor for CT3. One station service circuit breaker is rated at 13.8 kV, and the three others are rated at 600 volts. Each of these station service breakers perform a unique function and is critical to the operation of CT3. The current station service breakers and air compressor are original to the installation of CT3 in 2006.

***Justification***

The project is justified based on the need to have all CTs available for operation due to load growth and increased on-Island renewables in the Company's energy supply mix.

The spare breakers will reduce CT3 down time as they will be used to keep the unit operational when the existing breakers are sent away for testing. In the past, breaker testing has occurred on an approximately five-year cycle. Maritime Electric insurers are now recommending a shorter cycle as the availability of CT3 to operate when required is of increased importance to security of supply. Also, as delivery lead time for station service breakers is 12 to 14 weeks, having spares on hand will significantly reduce CT3 down time if a breaker failure occurs.

CT3 has two air compressors which serve to provide supply air to pneumatic valves on the water treatment system and for startup and shutdown of the CT3 turbine. One air compressor is always on, and the other is on standby, with operation rotated monthly to balance operating hours. Recently, one air compressor failed and has been replaced. The other air compressor, which is the same vintage as the one that failed, is nearing end of life.

***Costing Methodology***

The proposed budget allocation is based on vendor quotations for material and external labour.

A breakdown of the proposed budget for the CT3 spare and replacement parts is shown in Table 18. A contingency has been budgeted as this is a one-off project, the vendor quotation may need to be refreshed, some project component costs were estimated, and to accommodate minor adjustments in scope of supply that are commonly required with this type of project.

**TABLE 18**
**Breakdown of Proposed Budget**
**CT3 Spare and Replacement Parts**

| Description | Budget |
|---|---|
| Material and External Labour | $ 215,000 |
| Internal Labour and Transportation | 9,000 |
| Contingency (15 per cent) | 34,000 |
| **TOTAL** | **$ 258,000** |

Supporting information for the cost estimates included in Table 18 is provided in Confidential Appendix Q-4.

To ensure the project is completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for this project is January 2025.

***Alternatives***

There is no alternative to this project as the spare parts are required for security of supply.

***Future Commitments***

This is not a multi-year capital budget commitment.

## 4.3 Borden Generating Station - Buildings and Site Services *$ 65,000*

This category includes BGS expenditures required for building and site services projects, which includes necessary refurbishments, replacements and upgrades to the buildings and infrastructure within the BGS site.

The BGS site encompasses the following infrastructure inside the fence line at the Carleton Street site in Borden-Carleton: BGS maintenance building; two control room buildings; 69 kV Borden substation with two step-up power transformers X1 and X2; three diesel fuel storage tanks; a fuel tanker truck offloading facility; a lube oil storage building; two shipping container storage units; two storage buildings for spare lengths of submarine cable; and the adjacent 138 kV Borden riser station for submarine cables 3 and 4.

A breakdown of the historical expenditures, 2024 budget and the proposed 2025 budget for the BGS buildings and site services projects is shown in Table 19.

**TABLE 19**
**Historical and Proposed Capital Expenditures**
**BGS – Buildings and Site Services[a]**

| Description | 2020 | 2021 | 2022 | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material and External Labour | $ 74,000 | $ 20,992 | $ 167,149 | $ 59,078 | $ 21,000 | $ 48,000 |
| Internal Labour and Transportation | - | 6,154 | 136,200 | 13,569 | 16,000 | 17,000 |
| Other | - | - | - | - | - | - |
| **TOTAL** | **$ 74,000** | **$ 27,146** | **$ 303,349** | **$ 72,647** | **$ 37,000** | **$ 65,000** |

a. Prior to 2022, all BGS projects were included in the Borden Plant Projects category.

a. **BGS Miscellaneous Building and Site Upgrades (Recurring) $ 65,000**

As BGS buildings and site services age, upgrades are required each year to address deteriorated components. Experience indicates that unplanned and emergency events will also occur that require capital replacements, refurbishments and upgrades. Performing necessary replacement, refurbishment and upgrade work in a timely manner when the need arises, helps to ensure that BGS facilities remain in adequate condition for the safety of employees and to avoid costly emergency repairs or replacements.

As the projects under this budget category are unplanned and identified on an as-required basis, cost projections at the item level cannot be determined in advance and, therefore, the proposed budget is provisional.

***Justification***

The budget is justified on the obligation to ensure the efficient and safe operation and use of BGS facilities. For this reason, when projects arise throughout the year, they cannot be deferred.

***Costing Methodology***

A breakdown of the historical expenditures, 2024 budget and the proposed 2025 budget for BGS miscellaneous building and site upgrades is shown in Table 20.[17]

[17] The 2025 budget amount in Table 20 is based on a five-year average of actual and budgeted expenditures, from 2020 to 2024, that were normalized to 2025 dollars using an escalation rate of 3 per cent.

| TABLE 20<br>Historical and Proposed Capital Expenditures<br>BGS Miscellaneous Building and Site Upgrades | | | | | | |
|---|---|---|---|---|---|---|
| **Description** | **2020[a]** | **2021[b, c]** | **2022[d]** | **2023** | **2024 Budget** | **2025 Budget** |
| Material and External Labour | $ - | $ 11,971 | $ 159,174 | $ 27,056 | $ 21,000 | $ 48,000[e] |
| Internal Labour and Transportation | - | 3,907 | 50,949 | 7,807 | 16,000 | 17,000 |
| Other | - | 3,000 | 1,210 | - | - | - |
| **TOTAL** | **$ -** | **$ 18,878** | **$ 211,333** | **$ 34,863** | **$ 37,000** | **$ 65,000** |

a. There was no spending under this budget item in 2020.
b. In the 2021 Capital Budget, BGS – Buildings and Site Services and BGS – Turbine Generators were consolidated in Section 4.3 - Borden Plant Projects, with a budget of $113,000. It is estimated that approximately 10 per cent of the expenditures for "Borden Plant Projects" were required for BGS Buildings and Site Services, and approximately 90 per cent was required for BGS Turbine Generators.
c. Includes $1,777 for 2021 projects carried over and completed in 2022.
d. The budget for 2022 was higher than prior years due to changes in how expenditures are allocated and due to significant upgrades to the BGS maintenance building being required, as well as electrical and heating upgrades to other BGS buildings.
e. Includes the five-year average amount for "Other" expenditures.

To ensure this project is completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for this project is January 2025 with completion dates throughout the year.

### *Alternatives*

Alternatives will be considered at the time when BGS miscellaneous building and site upgrades are identified, as required.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring provisional capital requirement that is budgeted annually.

## 4.4 Borden Generating Station – Turbine Generators *$ 363,000*

This category includes expenditures associated with the generation equipment located at the BGS site, which includes CT1, CT2 and ancillary systems.

The CT1 and CT2 ancillary systems include ventilation and combustion air system; lube oil system; instrument air system; liquid fuel system; fire protection system; generator excitation system; vibration monitoring system; and other miscellaneous components.

The capital projects proposed in this category are critical to ensuring CT1 and CT2 are in a state that is ready to operate on demand.

A breakdown of the historical expenditures, 2024 budget and the proposed 2025 budget for BGS turbine generator projects is shown in Table 21.

**TABLE 21**
**Historical and Proposed Capital Expenditures**
**BGS - Turbine Generators[a]**

| Description | 2020 | 2021 | 2022 | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material and External Labour | $ 157,332 | $ 119,844 | $ 213,789 | $ 77,703 | $ 589,000 | $ 190,000 |
| Internal Labour and Transportation | 132,331 | 59,188 | 97,658 | 26,370 | 276,000 | 173,000 |
| Other | 1,753 | 5,279 | 86,412 | - | - | - |
| **TOTAL** | **$ 291,416** | **$ 184,311** | **$ 397,859** | **$ 104,073** | **$ 865,000** | **$ 363,000** |

a. Prior to 2022, all BGS projects were included in the Borden Plant Projects budget category.

**a. <u>BGS Combustion Turbine Improvements, Parts and Tools</u>**
**(Recurring) $ 152,000**

The proposed budget allocation is for the supply and installation of replacement equipment, critical parts and tools as required for the continued safe and reliable operation of the BGS.

As the projects under this budget category are unplanned and identified on an as-required basis, cost projections at the item level cannot be determined in advance and, therefore, the budget is provisional.

***Justification***

The project is justified based on the obligation of a public utility, under the *Electric Power Act*, to provide reasonably safe and adequate service, which requires the Company to manage all supply resources. The availability of CT1 and CT2 to operate when needed is of critical importance for security of supply.

***Costing Methodology***

The proposed provisional budget was estimated based on average historical expenditures for equipment replacements due to in-service failures. A breakdown of the historical expenditures, 2024 budget and proposed 2025 budget for BGS combustion turbine improvements, parts and tools is shown in Table 22.[18]

[18] The 2025 budget amount in Table 22 is based on a five-year average of actual and budgeted expenditures, from 2020 to 2024, that were normalized to 2025 dollars using an escalation rate of 3 per cent.

| TABLE 22<br>Historical and Proposed Capital Expenditures<br>BGS Combustion Turbine Improvements, Parts and Tools | | | | | | |
|---|---|---|---|---|---|---|
| **Description** | **2020** | **2021[a b]** | **2022** | **2023** | **2024 Budget** | **2025 Budget** |
| Material and External Labour | $ 217,416 | $ 31,583 | $ 104,587 | $ 40,850 | $ 113,000 | $ 119,000[c] |
| Internal Labour and Transportation | - | 27,629 | 31,061 | 91,688 | 5,000 | 33,000 |
| Other | - | 2,006 | 28,267 | - | - | - |
| **TOTAL** | **$ 217,416** | **$ 61,218** | **$ 163,915** | **$ 132,538** | **$ 118,000** | **$ 152,000** |

a. In the 2021 Capital Budget, BGS – Buildings and Site Services and BGS – Turbine Generators were consolidated in Section 4.3 - Borden Plant Projects, with a budget of $113,000. It is estimated that approximately 10 per cent of the expenditures for “Borden Plant Projects” was required for BGS Buildings and Site Services, and approximately 90 per cent was required for BGS Turbine Generators.
b. Includes 90 per cent of $1,777 for 2021 projects carried over and completed in 2022.
c. Includes the five-year average for “Other” expenditures.

To ensure this project is completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for this project is January 2025 with in-service dates throughout the year, as required.

***Alternatives***

There is no alternative to this project. The BGS combustion turbines provide critical backup generation capability and the consequence of not having readily available funds to enable the acquisition of critical parts or replacements due to unforeseen in-service failures, could result in the equipment not being available for operation when required.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring provisional capital requirement that is budget annually.

**b. <u>CT1 Power Turbine Inspection</u> (Justifiable) $ 211,000**

This project involves the inspection of the power turbine for CT1. The proposed inspection will determine if the overall condition of CT1 has changed since the last such inspection was completed in 2011.

***Justification***

Periodic inspection of combustion turbine generation equipment is necessary to identify issues that could lead to premature failure of critical components. During a 2011 inspection of the power turbine of CT1, the power turbine nozzle was determined to have cracks, a common problem with this type of turbine. The planned inspection will include determining if these cracks have propagated and if so, to what extent. In the case of no change since 2011, no remedial action is required; however, if small changes have occurred refurbishment will be considered, and if the cracks have increased significantly, replacement will be necessary.

As a source of emergency energy and ten-minute non-spinning reserve, the ability of CT1 to be operational when required is both expected and critical to security of supply. In the event of the cracks in the power turbine nozzle causing the nozzle to fail, CT1 would be forced out of service for an extended period. For these reasons, inspection of CT1’s power turbine is necessary to determine if there are any components in immediate need of repair, refurbishment, or replacement.

***Costing Methodology***

The proposed budget is based on a combination of vendor quotations for material and external labour, and professional engineering estimates for internal labour and transportation.

A breakdown of the proposed budget for the CT1 power turbine and gearbox inspection is shown in Table 23. A contingency has been budgeted as this is a one-off project, the vendor quotation may need to be refreshed, some project component costs were estimated, and to accommodate minor adjustments in scope of supply that are commonly required with this type of project.

**TABLE 23**
**Breakdown of Proposed Budget**
**CT1 Power Turbine Inspection**

| Description | Budget |
|---|---|
| Material and External Labour | $ 43,000 |
| Internal Labour and Transportation | 140,000 |
| Contingency (15 per cent) | 28,000 |
| **TOTAL** | **$ 211,000** |

Supporting information for the cost estimates included in Table 23 is provided in Confidential Appendix Q-4.

To ensure the project is completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for this project is May 2025 and the expected completion date is June 2025.

***Alternatives***

There is no alternative to this project. CT1 provides critical backup generation capability and as such, must be regularly inspected to ensure that parts are in good operating condition, or upgraded through refurbishment or replacement, if necessary.

***Future Commitments***

This is not a multi-year capital budget commitment; however, inspection may identify some refurbishment or replacement work to be completed in future years.

## 5.0 DISTRIBUTION $ 43,772,000

Maritime Electric's proposed 2025 capital expenditures for distribution were developed using the Company's ISP and DAMP, and enables the replacement of aged infrastructure, and distribution system modifications to maintain/improve reliability, accommodate load growth, advance the Company's climate change adaptation priorities, and ensure continued compliance with all safety and environmental requirements. In addition, distribution assets will be installed to serve new customers, modify existing service connections, address system load growth impacts and facilitate joint use of utility poles with communication providers. The Company's asset database, field inspection results, and reliability data is used to identify facilities and equipment for priority replacement.

### 5.1 Replacements Due to Storms, Collisions, Fire, and Road Alterations *$ 2,224,000*

This provisional budget is required for capital replacements due to storms, motor vehicle accidents, fire, other emergency incidents and road alterations. The amount for 2025 is shown in Table 24.[19,20]

**TABLE 24**
**Historical and Proposed Capital Expenditures**
**Replacements Due to Storms, Collisions, Fire, and Road Alterations**

| Description | 2020 | 2021 | 2022 | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 411,621 | $ 483,296 | $ 302,165 | $ 538,667 | $ 458,000[a] | $ 488,000[a] |
| Contractor Labour | 517,043 | 528,127 | 346,180 | 967,638 | 580,000 | 515,000 |
| Internal Labour and Transportation | 873,796 | 726,159 | 1,344,865 | 1,371,881 | 973,000 | 1,221,000 |
| Other | 13,624 | 2,473 | 82,666 | 34,371 | - | - |
| **TOTAL** | $1,816,084 | $1,740,055 | $2,075,876 | $2,912,557 | $ 2,011,000 | $ 2,224,000 |

a. Includes the five-year average amount for "Other" expenditures.

[19] The 2025 budget amount in Table 24 is based on a five-year average of actual and budgeted expenditures, from 2020 to 2024, that were normalized to 2025 dollars using an annual escalation rate of 3 per cent.

[20] For the 2025 Budget, the sum total of "Contractor Labour" and "Internal Labour and Transportation" equals the five-year average for labour, not the individual amounts for each item.

**a. Replacements Due to Storms, Collisions, and Fire (Recurring) $ 1,236,000**

Maritime Electric operates approximately 6,000 km of distribution lines to serve customers within its service territory. When damage occurs to distribution structures and equipment, the Company is obligated to respond in a timely manner and restore the electrical system to a safe and reliable operating condition. The scope and severity of damage caused by storms and other adverse events can be highly variable from year to year. For this reason, the budgeted amount is a provisional cost estimate for labour and material that will be required to replace distribution equipment (predominantly poles, transformers and wire) damaged as a result of unforeseen events that are beyond the Company's control.

This budget differs from the budget allocation in Section 5.5 - Line Rebuilds, as the work is unplanned and is necessary to address operational events, including power interruptions and customer trouble calls.

***Justification***

The provisional budget for distribution system replacements due to storms, collisions, and fire is justified on the obligation to provide safe and reliable service to customers and cannot be deferred.

***Costing Methodology***

A breakdown of the historical expenditures, 2024 budget and the proposed 2025 budget for the storm response and other outage restoration activity that the Company is obligated to provide is shown in Table 25.[21]

[21] The 2025 Budget amount in Table 25 is based on a five-year average of actual and budgeted expenditures, from 2020 to 2024, that were normalized to 2025 dollars using an annual escalation rate of 3 per cent.

| TABLE 25<br>Historical and Proposed Expenditures<br>Replacements Due to Storms, Collisions, and Fire | | | | | | |
|---|---|---|---|---|---|---|
| **Description** | **2020** | **2021** | **2022** | **2023** | **2024 Budget** | **2025 Budget** |
| Material | $ 196,970 | $ 175,252 | $ 186,054 | $ 263,688 | $ 226,000[a] | $ 241,000[a] |
| Contractor Labour | 120,973 | 42,466 | 173,530 | 429,539 | 192,000 | 206,000 |
| Internal Labour and Transportation | 667,791 | 506,391 | 942,529 | 868,108 | 622,000 | 789,000 |
| Other | 8,162 | 2,473 | 39,140 | 17,401 | - | - |
| **TOTAL** | **$ 993,896** | **$ 726,582** | **$1,341,253**[b] | **$ 1,578,736** | **$1,040,000** | **$1,236,000** |

a. Includes the five-year average amount for “Other” expenditures.
b. Does not include costs associated with Fiona, which are currently deferred by Commission Order UE22-08.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring provisional capital requirement that is budgeted annually.

**b. <u>Replacements Due to Road Alterations</u> (Recurring) $ 988,000**

Each year, the Company relocates or replaces distribution and transmission assets to accommodate Provincial Government activities in public rights-of-way. The most common activities requiring the relocation or replacement of distribution and transmission assets are related to infrastructure projects such as sidewalk installations, sewer and water line extensions, road widening, road construction and bridge replacements. At the time that the 2025 Capital Budget was developed, Provincial Government plans for infrastructure work in 2025 were not yet confirmed and, therefore, a provisional amount has been budgeted.

Requests by other entities to relocate or replace Company assets are governed by the provisions of any agreements between the Company and the requesting parties, or are dealt with on a case-by-case basis.

### Justification

The provisional budget allocation for distribution system replacements due to road alterations is justified on the obligation to ensure the safe and reliable operation of the electrical system and cannot be deferred.

### Costing Methodology

A breakdown of the historical expenditures, 2024 budget and the proposed 2025 budget for system alteration activities in public rights-of-way that the Company is obligated to provide, is shown in Table 26.[22]

**TABLE 26**
**Historical and Proposed Capital Expenditures**
**Replacements Due to Road Alterations**

| Description | 2020 | 2021 | 2022 | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 214,651 | $ 308,043 | $ 116,111 | $ 199,670 | $ 232,000[a] | $ 247,000[a] |
| Contractor Labour | 396,070 | 485,660 | 172,650 | 421,889 | 388,000 | 309,000 |
| Internal Labour and Transportation | 206,005 | 219,768 | 402,336 | 341,817 | 351,000 | 432,000 |
| Other | 5,462 | - | 43,526 | 15,732 | - | - |
| **TOTAL** | **$ 822,188** | **$1,013,471** | **$ 734,623** | **$ 979,108** | **$ 971,000** | **$ 988,000** |

a. Includes the five-year average amount for “Other” expenditures.

### Future Commitments

This is not a multi-year capital budget commitment; however, it is a recurring provisional capital requirement that is budgeted annually.

[22] The 2025 Budget amount in Table 26 is based on a five-year average of actual and budgeted expenditures, from 2020 to 2024, that were normalized to 2025 dollars using an annual escalation rate of 3 per cent.

### 5.2 Distribution Transformers (Recurring/Mandatory[23]) *$ 15,908,000*

The purchase and installation of new distribution transformers and other related equipment is an annual recurring capital budget expenditure that is required to serve new customers, accommodate changes for existing customers and replace deteriorated or damaged units. This requirement has steadily grown in recent years due to the increase in the number of new services related to housing starts and population growth.

Maritime Electric expects transformer requirements to increase in 2025 based on new customer requirements, and necessary equipment replacements, upgrades and retirements. As such, the Company has budgeted for 2,553 polemount, 12 stepdown, and 58 padmount transformers in 2025.[24]

There has been some leveling off of transformer cost increases over the past year, but supply chain constraints continue to be a challenge as limited inventory at the supplier level reduces the availability of certain types and capacities of transformers, and delivery times increase when units are out of stock and backordered.

The Provincial Government introduced a new Oil to Heat Pump Affordability ("OHPA") program in 2024 which has increased the transformer requirements beginning in 2024 and continuing through 2026. Through the OHPA program, approximately 1,000 Island residences per year will be converted from space heating with oil, to electrically operated heat pumps. The Company estimates that annually, 300 of these conversions will require a transformer upgrade due to the increased energy supply requirement. Additionally, a Provincial Government initiative to install Level 3 electric vehicle ("EV") chargers across PEI is included in the estimated requirement for padmount transformers.

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23 Mandatory replacement of transformer equipment containing PCBs is budgeted at $754,000, which is included in this proposed budget for distribution transformers.

24 In 2024, the Capital Budget reflected 1,730 polemount and 111 padmount transformers.

Work to replace PCB containing electrical equipment will continue in 2025, to ensure compliance with the December 31, 2025 federally regulated replacement deadline.[25] Maritime Electric is on schedule to be fully compliant with federal requirements by the legislated deadline.

***Justification***

The budget for distribution transformers is justified based on the need to maintain safe, reliable electrical service at least cost, and the obligation to provide equitable access to an adequate supply of power to new and existing customers. For the reasons provided, it cannot be deferred.

***Costing Methodology***

The budget for distribution transformers is based on the previous year's usage, upcoming line rebuilds, new housing start forecasts, replacements resulting from government electrification programs, transformer inspections and current equipment costs, as shown in Table 27. Supporting information for the 2025 distribution transformer budget is provided in Confidential Appendix Q-5.

**TABLE 27**
**Historical and Proposed Capital Expenditures**
**Distribution Transformers**

| Description | 2020[a] | 2021 | 2022[b] | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $3,243,305 | $5,083,289 | $5,000,069 | $10,566,340 | $12,986,000 | $ 14,512,000 |
| Contractor Labour | 36,652 | 51,175 | 14,779 | 60,988 | 52,000 | 54,000 |
| Internal Labour and Transportation | 600,717 | 759,863 | 801,588 | 1,139,102 | 1,358,000 | 1,342,000 |
| Other | 39,845 | 46,084 | 13,059 | 5,101 | - | - |
| **TOTAL** | **$3,920,519** | **$5,940,411** | **$5,829,495** | **$11,771,531** | **$14,396,000** | **$ 15,908,000** |

a. Includes $110,927 for 2020 transformers carried over and delivered in 2021.
b. Includes $1,365,000 for 2022 projects carried over and completed in 2023.

[25] Federal regulations state that polemount electrical transformers and their polemount auxiliary electrical equipment as well as current transformers, potential transformers, circuit breakers, reclosers and bushings that are located at an electrical generation, transmission or distribution facility, which contain PCBs in a concentration of 50 ppm or more, have an end of use deadline of December 31, 2025.

To ensure this project is completed at the lowest possible cost, all material will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material requires sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for this project is January 2025 and will continue with in-service dates throughout the year.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is recurring capital requirement that is budgeted annually.

### 5.3 Services and Street Lighting *$ 9,702,000*

This provisional budget provides for the construction of service lines to connect new customers, refurbishment of aged service lines, and installation of new street lights and replacement of existing street lights with energy efficient light-emitting diode ("LED") fixtures. The services and street lighting expenditures are expected to be partially offset by customer contributions for construction charges as set by the General Rules and Regulations of the Company.

A breakdown of the historical expenditures, 2024 budget and proposed 2025 budget for overhead and underground services work that the Company is obligated to provide is shown in Table 28.

| TABLE 28<br>Historical and Proposed Capital Expenditures<br>Services and Street Lighting | | | | | | |
|---|---|---|---|---|---|---|
| **Description** | **2020** | **2021** | **2022** | **2023** | **2024 Budget** | **2025 Budget** |
| Material | $1,271,480 | $1,444,434 | $2,151,429 | $2,453,476 | $1,651,000[a] | $2,200,000[a] |
| Contractor Labour | 422,633 | 1,024,810 | 738,714 | 1,870,296 | 711,000 | 750,000 |
| Internal Labour and Transportation | 3,463,387 | 3,956,116 | 3,753,261 | 4,106,340 | 4,803,000 | 6,752,000 |
| Other | 75,671 | 55,937 | 123,086 | 229,928 | - | - |
| **TOTAL** | **$5,233,171** | **$6,481,297** | **$6,766,490** | **$8,660,040** | **$7,165,000** | **$9,702,000** |

a. Includes the five-year average amount for "Other" expenditures.

**a. Overhead and Underground Services (Recurring) $ 9,110,000**

Services work involves the installation and replacement of distribution wires that connect a customer's electrical service equipment to the Company's transformers, and the transformers to the main line.[26] The volume of new and replacement services work fluctuates from year to year; however, strong demand for new services and service connection modifications has been experienced in recent years.[27]

The Provincial Government's new OHPA program is further increasing the demand for service work and the proposed budget for overhead and underground services reflects this additional activity. The Company estimates that 80 per cent of OHPA program participants will require a larger capacity electrical service, which will also necessitate distribution system upgrades to support the increased energy requirements.

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26 Replacement of existing service wires is typically due to deterioration, failure, damage, or to accommodate increased customer load.

27 A portion of the strong demand for new services and service connection modifications has been to accommodate customer installations of heat pumps, solar panels and EV chargers, which are being driven by Provincial Government incentive programs.

***Justification***

The provisional budget for overhead and underground services work is justified on the obligation to provide equitable access to an adequate supply of power to new and existing customers and cannot be deferred.

***Costing Methodology***

The provisional budget for overhead and underground services as shown in Table 29 is based on a five-year average of actual and budgeted expenditures from 2020 to 2024,[28, 29] plus additional costs associated with the OHPA program. The budget amount for labour, in addition to the five-year average plus the OHPA program, also includes the additional costs for new powerline technician positions that were established in 2024 to respond to the increased workload.

**TABLE 29**
**Historical and Proposed Capital Expenditures**
**Overhead and Underground Services**

| Description | 2020 | 2021 | 2022 | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 906,081 | $1,035,009 | $1,612,325 | $ 1,396,763 | $1,201,000[a] | $1,891,000[a] |
| Contractor Labour | 422,633 | 1,010,142 | 708,714 | 1,810,020 | 695,000 | 750,000 |
| Internal Labour and Transportation | 3,034,889 | 3,511,007 | 3,305,751 | 3,703,255 | 4,198,000 | 6,469,000 |
| Other | 75,671 | 55,937 | 123,086 | 229,724 | - | - |
| **TOTAL** | **$4,439,274** | **$5,612,095** | **$5,749,876** | **$ 7,139,762** | **$6,094,000** | **$9,110,000** |

a. Includes the five-year average amount for “Other” expenditures.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring provisional capital requirement that is budgeted annually.

28 Actual and budgeted expenditures, from 2020 to 2024, were normalized to 2025 dollars using an annual escalation rate of 3 per cent, prior to calculating the five-year average.

29 For the 2025 Budget, the sum total of “Contractor Labour” and “Internal Labour and Transportation” equals the five-year average for labour, not the individual amounts for each item.

**b. Street and Area Lighting (Recurring) $ 592,000**

Street and area lighting is an established service offered by Maritime Electric. The 2025 provisional budget amount allows for the installation of approximately 700 LED street and yard lights based on the historical level of customer requests and light replacements due to fixtures reaching the end of their useful life. Compared to the 2024 Capital Budget, which budgeted for a total of 1,400 street light installations, the number of street lights planned for 2025 is significantly reduced. The reduction reflects the completion of the ten-year LED street light conversion program in 2024, which completed approximately 900 replacements annually. The estimate for new LED light installations has increased from 500 in 2024 to 700 in 2025, to match recent customer light requests and anticipated end-of-life replacements.

***Justification***

The provisional budget for street and area lighting is justified on the obligation to serve new and existing customers with equitable access to lighting services and cannot be deferred.

***Costing Methodology***

A breakdown of the historical expenditures, 2024 budget and the proposed 2025 budget for street and area lighting service that the Company is obligated to provide is shown in Table 30.

**TABLE 30**
**Historical and Proposed Capital Expenditures**
**Street and Area Lighting**

| Description | 2020 | 2021 | 2022 | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 365,399 | $ 409,425 | $ 539,104 | $ 1,056,713 | $ 450,000 | $ 309,000 |
| Contractor Labour | - | 14,668 | 30,000 | 60,276 | 16,000 | - |
| Internal Labour and Transportation | 428,498 | 445,109 | 447,510 | 403,085 | 605,000 | 283,000 |
| Other | - | - | - | 204 | - | - |
| **TOTAL** | **$ 793,897** | **$ 869,202** | **$1,016,614** | **$1,520,278** | **$1,071,000** | **$ 592,000** |

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring provisional capital requirement that is budgeted annually.

## 5.4 Line Extensions *$ 3,644,000*

Line extension projects involve the construction of both primary and secondary distribution lines to connect new customers to the electrical system or to upgrade the capacity of existing lines to accommodate increased customer loads. Line extensions can also be initiated by the Company to cost effectively redistribute system loads by reconfiguring feeders or establishing new feeders for overall improvements in system reliability and operability.

Line extension work to connect new customers or accommodate increased customer-specific loads is categorized as customer driven line extensions. This category includes a provisional budget amount for typical work to main lines that is associated with connecting new customers to the electrical system. This category also includes a provisional budget amount for completing system upgrades to accommodate customer-specific load increases. Customer driven line extensions also improve reliability due to the upgrades being constructed to meet current standards and designs. Costs associated with the extension of lines to reach specific customers that do not already have the requested service (including single phase customers requesting three phase service) are expected to be partially offset by customer contributions. Customer driven line extensions associated with upgrading existing facilities to accommodate customer load growth are the responsibility of the utility.

Line extension projects to redistribute electrical system loads and to reduce the impacts to customers from electric faults are categorized as load and reliability driven line extensions. Load and reliability driven line extensions can provide reduced feeder length and reduced customer numbers per feeder. Both contribute to increased reliability. Single to three phase line extensions are often required to provide voltage support and to redistribute single phase load across three phases, which allows for the use of standard fusing. When appropriate, the line extension projects are constructed with the capability to supply main feeders from more than a single source.

A breakdown of the historical expenditures, 2024 budget and the proposed 2025 budget for customer driven line extension work that the Company is obligated to provide is shown in Table 31.

**TABLE 31**
**Historical and Proposed Capital Expenditures**
**Line Extensions**

| Description | 2020[a] | 2021 | 2022 | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 1,096,282 | $ 1,135,187 | $ 821,327 | $ 836,994 | $ 1,020,000 | $ 901,000[b] |
| Contractor Labour | 1,290,375 | 928,010 | 2,128,479 | 2,096,727 | 2,389,000 | 1,256,000 |
| Internal Labour and Transportation | 1,287,603 | 989,452 | 1,255,818 | 1,278,742 | 1,420,000 | 1,487,000 |
| Other | 6,788 | (194,174) | 18,210 | 163,614 | - | - |
| **TOTAL** | **$ 3,681,048** | **$ 2,858,475** | **$ 4,223,834** | **$ 4,376,077** | **$ 4,829,000** | **$ 3,644,000** |

a. Includes $303,354 for a 2020 project carried over and completed in 2021.
b. Includes the five-year average amount for “Other” expenditures.

**a. Customer Driven Line Extensions (Recurring) $ 2,161,000**

Line extension work will involve both upgrades to existing infrastructure and new construction of single phase and three phase distribution lines to serve all types of customers and customer driven supply requirements.

***Justification***

The provisional budget for customer driven line extensions is justified on the obligation to provide equitable access to an adequate supply of power to new and existing customers and cannot be deferred.

***Costing Methodology***

The budget as shown in Table 32 is based on a five-year average of actual and budgeted expenditures from 2020 to 2024.[30]

**TABLE 32**
**Historical and Proposed Capital Expenditures**
**Customer Driven Line Extensions**

| Description | 2020 | 2021 | 2022 | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 638,240 | $ 890,020 | $ 320,727 | $ 517,828 | $ 623,000[a] | $ 668,000 |
| Contractor Labour | 114,369 | 617,310 | 592,165 | 625,882 | 576,000 | 220,000 |
| Internal Labour and Transportation | 1,012,452 | 720,157 | 570,727 | 962,474 | 1,075,000 | 1,273,000 |
| Other | 1,691 | 7,273 | 36,355 | 6,802 | - | - |
| Less: Joint Use Charged To/ Owned by Third Party | - | (208,406) | - | - | - | - |
| **TOTAL** | **$ 1,766,752** | **$ 2,026,354** | **$ 1,519,974** | **$ 2,112,986** | **$ 2,274,000** | **$ 2,161,000** |

a. Includes the five-year average amount for "Other" expenditures and the five-year average amount for "Less: Joint use Charge To/Owned by Third Party".

Customer driven line extension expenditures are expected to be partially offset by customer contributions.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring provisional capital requirement that is budgeted annually.

**b. <u>Load and Reliability Driven Line Extensions</u> (Justifiable) $ 1,483,000**

The proposed budget provides for the extension of single and three phase distribution lines including joint use lines. Projects are prioritized based on the need to relieve highly loaded feeders, balance load on three phase lines, address

[30] For the 2025 Budget, the sum total of "Contractor Labour" and "Internal Labour and Transportation" equals the five-year average for labour, not the individual amounts for each item.

projected load growth, and improve reliability by creating alternative feed pathways.

The following load driven line extension project is planned for 2025:

i. Blue Shank Road Three Phase Conversion

***Justification***

The planned load driven line extension project is justified based on the obligation to provide safe and reliable service to customers. Additional details and justifications for this project is provided in Appendix J.

***Costing Methodology***

A breakdown of the historical expenditures, 2024 budget and proposed 2025 budget for load and reliability driven line extensions is provided in Table 33.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring provisional capital requirement that is budgeted annually.

**TABLE 33**
**Historical and Proposed Capital Expenditures**
**Load and Reliability Driven Line Extensions**

| Description | 2020[a] | 2021 | 2022 | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 458,042 | $ 245,167 | $ 188,315 | $ 319,166 | $ 397,000 | $ 233,000 |
| Contractor Labour | 1,176,006 | 310,700 | 629,606 | 1,470,845 | 1,813,000 | 1,036,000 |
| Internal Labour and Transportation | 275,151 | 270,000 | 306,852 | 316,268 | 345,000 | 214,000 |
| Other | 5,097 | 6,255 | 3,962 | 156,812 | - | - |
| Less: Joint Use Charged To/ Owned by Third Party | - | - | (51,725) | - | - | - |
| **TOTAL** | **$1,914,296** | **$ 832,122** | **$1,077,010** | **$2,263,091** | **$2,555,000** | **$1,483,000** |

a. Includes $303,354 for a 2020 project carried over and completed in 2021.

## 5.5 Line Rebuilds *$ 6,813,000*

The projects and programs proposed in the line rebuilds budget category enable the Company to address the timely replacement of aged infrastructure, improve reliability and power quality, reduce electrical losses, and improve safety for workers by upgrading the system to meet current construction standards. The Company's asset database, field inspection results, and reliability data serve as the primary tools for planning single and three phase rebuilds, pole and component replacements and other reliability improvement activities. Projects initiated by third-party telecommunication companies requesting joint use line conversions to accommodate communication equipment are also included in this category. The communications make-ready requests are customer driven and are often received without advance notice; however, the Company is still obligated to complete such work in a timely manner. As such, longer communications make-ready projects are not budgeted and instead reported to the Commission quarterly through capital expenditure forecasts and when warranted,[31] through the SCBR process. Customer driven capital expenditures, including communication make-ready requests, can be fully or partially offset by a contribution, depending upon the specifics of the project.

A breakdown of the historical expenditures, 2024 budget and proposed 2025 budget for line rebuilds is shown in Table 34.

[31] The PEI Broadband Project is an example of a larger communication make-ready project that warranted an SCBR application, as it was multi-year with work locations through the province.

**TABLE 34**
**Historical and Proposed Capital Expenditures**
**Line Rebuilds**

| Description | 2020 | 2021[c] | 2022 | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 798,628 | $ 990,614 | $ 695,914 | $ 1,310,623 | $1,088,000 | $ 1,022,000 |
| External Labour | 1,960,459 | 2,340,981 | 1,974,801 | 2,560,912 | 4,279,000 | 4,155,000 |
| Internal Labour and Transportation | 1,128,543 | 1,238,058 | 1,298,764 | 1,461,780 | 1,647,000 | 1,279,000 |
| Other | 29,823 | 54,590 | 18,702 | 2,088 | - | 357,000 |
| PEI Broadband | 9,190,493[a] | 4,431,318[d] | 6,735,307[e] | - | - | - |
| Less: Joint Use Charged to/Owned by Third Party | (3,614,883)[b] | (265,986) | (90,381) | - | - | - |
| **TOTAL** | **$ 9,493,063** | **$ 8,789,575** | **$10,633,107** | **$ 5,335,403** | **$ 7,014,000** | **$ 6,813,000** |

a. Includes $3,204,204 in actual and $2,506,000 budgeted for 2020 PEI Broadband Project work carried over to be completed in 2023.
b. $3,480,427 of joint use charges relates to PEI Broadband Project.
c. Includes $603,052 for 2021 eastern cedar pole replacement program work carried over and completed in 2022.
d. Includes $3,542,379 for 2021 PEI Broadband Project work carried over and completed in 2022.
e. Includes $2,072,054 in 2022 actual costs, $3,363,253 in 2023 costs and $1,300,000 for 2022 PEI Broadband Project work to be carried over and completed in 2024.

**a. <u>Single Phase and Three Phase Line Rebuilds</u> (Justifiable) $ 2,372,000**

The budget provides for the rebuilding of single phase and three phase distribution lines including joint use lines. Projects are identified for rebuild based on the condition of system assets such as poles and wire, length of spans, historical reliability issues associated with the line, and historical and projected load growth in the area.

The proposed rebuilds will improve reliability and power quality, allow for future load growth, and reduce system losses. The rebuilds will also improve safety for power line technicians by upgrading old lines to modern construction standards with increased clearances and updated system equipment. Line rebuilds are also constructed to meet the Company's climate change adaptation specifications. The rebuild projects planned for 2025 are on lines with numerous eastern cedar poles that are approximately 50 years old and/or that have damaged or deteriorated conductor.

The following single phase and three phase line rebuilds are planned for 2025:

i. Alberton to Elmsdale Line Rebuild; and
ii. Keppoch Road Line Rebuild.

***Justification***

The planned single and three phase line rebuild projects are justified on the obligation to provide safe and reliable service to customers and cannot be deferred. Additional details and justifications for these projects is provided in Appendix K.

***Costing Methodology***

A breakdown of the historical expenditures, 2024 budget and proposed 2025 budget for single and three phase line rebuild projects is shown in Table 35. The budget amount for each project is a function of the work location (e.g., travel distance), distance covered by the rebuild, requirements for traffic control, the customer density along the line, the applicable construction design standard (e.g., single or three phase, joint use, etc.), and construction methods required in the field (e.g., energized, de-energized, etc.).

**TABLE 35**
**Historical and Proposed Capital Expenditures**
**Single Phase and Three Phase Line Rebuilds**

| Description | 2020 | 2021 | 2022 | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 502,601 | $ 590,220 | $ 308,576 | $ 573,267 | $ 450,000 | $ 365,000 |
| Contractor Labour | 1,379,381 | 1,308,585 | 697,755 | 1,036,882 | 1,866,000 | 1,670,000 |
| Internal Labour and Transportation | 307,485 | 683,106 | 688,568 | 795,529 | 771,000 | 337,000 |
| Other | 28,212 | - | 264 | 8,901 | - | - |
| Less: Joint Use Charged to/Owned by Third Party | (134,115) | (212,582) | (65,814) | - | - | - |
| **TOTAL** | **$ 2,083,564** | **$ 2,369,329** | **$1,629,349** | **$2,414,579** | **$3,087,000** | **$ 2,372,000** |

***Future Commitments***

None of the proposed line rebuild projects are multi-year capital budget commitments.

**b. <u>Distribution Line Refurbishment</u> (Recurring) $ 881,000**

The Company's distribution inspection program is a proactive way to improve reliability through identifying components of the distribution system that are unsafe or at risk of failure. The program was designed to ensure that all overhead primary distribution lines are subject to a detailed ground inspection every six years.

The structured inspection and refurbishment of distribution lines plays a critical role in extending and/or maintaining their lifespan, enhancing employee and public safety, and improving system reliability by reducing the probability of component failure. Photographs of deficiencies identified through distribution line inspection are shown in Appendix L.

***Justification***

The timely replacement or refurbishment of deteriorated distribution structures and equipment is justified on the obligation to maintain a safe and reliable electrical system and cannot be deferred.

***Costing Methodology***

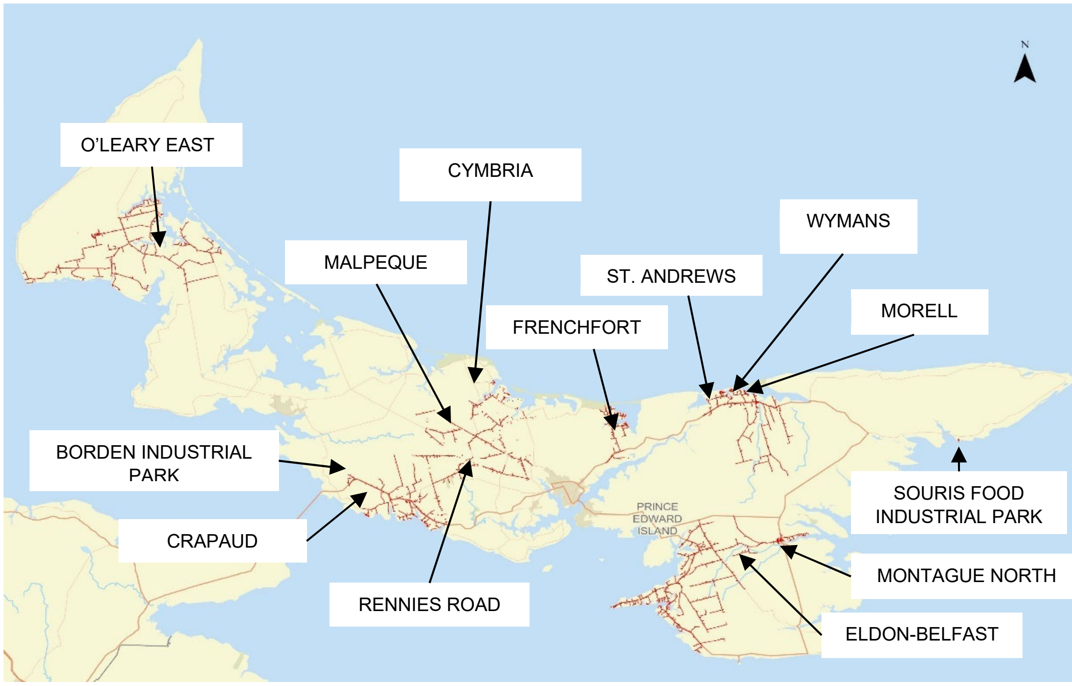
A breakdown of the historical expenditures, 2024 budget and proposed 2025 budget for distribution line refurbishment is shown in Table 36.

| **TABLE 36**<br>**Historical and Proposed Capital Expenditures**<br>**Distribution Line Refurbishment** | | | | | | |
|---|---|---|---|---|---|---|
| **Description** | **2020** | **2021** | **2022** | **2023** | **2024 Budget** | **2025 Budget** |
| Material | $ 115,947 | $ 151,540 | $ 131,233 | $ 160,814 | $ 152,000 | $ 157,000 |
| Contractor Labour | 127,162 | 116,133 | 123,217 | 181,692 | 176,000 | 181,000 |
| Internal Labour and Transportation | 499,475 | 473,189 | 493,256 | 501,676 | 527,000 | 543,000 |
| Other | 168 | (1,643) | 221 | 1,256 | - | - |
| **TOTAL** | **$ 742,752** | **$ 739,219** | **$ 747,927** | **$ 845,438** | **$ 855,000** | **$ 881,000** |

The budget will allow for inspection of feeders identified in Table 37 and the prioritized replacement of deteriorated assets such as poles, crossarms, conductors and hardware. The locations of the feeders are provided in Figure 8.

| **TABLE 37**<br>**Distribution Feeders to be Inspected in 2025** | | |
|---|---|---|
| **Feeders** | **Kilometres** | **Number of Customers** |
| Crapaud [AB33125] | 104 | 1,322 |
| Borden Industrial Park [AB33126] | 4 | 8 |
| Cymbria [BG56500] | 52 | 967 |
| Rennies Road [HR00721] | 104 | 1,448 |
| Malpeque [HR00778] | 76 | 754 |
| Frenchfort [MF62100] | 47 | 761 |
| O'Leary East [OL00971] | 207 | 2,273 |
| Souris Food Industrial Park [SO13113] | 1 | 8 |
| Montague North [VC02301] | 21 | 1,001 |
| Eldon-Belfast [VC01440] | 212 | 1,639 |
| Morell [WP12400] | 98 | 990 |
| Wymans [WP12100] | 0.4 | 2 |
| St. Andrews [WP12200] | 22 | 342 |
| **TOTAL** | **948.4** | **11,515** |

**FIGURE 8**
**2025 Distribution Feeder Inspection Locations**




***Future Commitments***

Distribution inspection and refurbishment is structured on a six-year cycle pending approval annually through the Company's capital budget application. As such, this is not a multi-year capital budget commitment; however, it is a recurring capital program that is budgeted annually.

**c.** **<u>Accelerated Distribution Component Replacement</u>**
**(Justifiable)** **$ 2,277,000**

This proposed budget provides for the accelerated replacement of eastern cedar poles and deteriorated conductor, as well as the relocation of backlot feed lines. Rationale and justification for each program follows.

***i.*** ***<u>Eastern Cedar Pole Replacement Program</u>*** ***$ 1,343,000***

Most eastern cedar poles in the Company's distribution system are approximately 50 years old. Prior to the program, these poles were being replaced through a combination of rebuild projects and storms at a total rate of approximately 900 per year. As such, it was estimated in 2018 that it would take up to 20 years to replace the 16,000 eastern cedar poles remaining in the system.

With the addition of the program to accelerate the replacement of eastern cedar poles in 2019, the target replacement rate was increased to approximately 1,500 poles per year. This improved the timeframe for substantial removal of all eastern cedar distribution poles to approximately 10 years. It is currently estimated that there will be 7,000 eastern cedar poles remaining to be replaced at the end of 2024.

### *Justification*

The accelerated replacement of eastern cedar poles is justified on the obligation to maintain a safe and reliable electrical system and cannot be deferred beyond what is proposed in the Application.

### *Costing Methodology*

A breakdown of the historical expenditures, 2024 budget and the proposed 2025 budget for the eastern cedar pole replacement program is shown in Table 38.

**TABLE 38**
**Historical and Proposed Capital Expenditures**
**Eastern Cedar Pole Replacement Program**

| Description | 2020[a] | 2021[b] | 2022 | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 118,123 | $ 121,196 | $ 225,105 | $ 215,735 | $ 248,000 | $ 255,000 |
| Contractor Labour | 396,359 | 1,024,742 | 1,113,829 | 1,000,210 | 975,000 | 1,005,000 |
| Internal Labour and Transportation | 250,096 | 31,291 | 87,875 | 54,300 | 81,000 | 83,000 |
| Other | 1,444 | 2,827 | 18,217 | - | - | - |
| **TOTAL** | **$ 766,022** | **$1,180,056** | **$1,445,026** | **$1,270,245** | **$1,304,000** | **$1,343,000** |

a. In 2020, the program budget was decreased to reflect an expectation that the PEI Broadband Project would result in a significant number of eastern cedar pole replacements. This did not occur and targeted replacements under the program was returned to 2019 levels in 2021.
b. Includes $603,052 for 2021 projects carried over and completed in 2022.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring capital requirement that is budgeted annually for the duration of the program.

***ii. <u>Deteriorated Conductor Replacement Program</u> $ 445,000***

The deteriorated conductor replacement program is targeted at replacing aged and deteriorated copper conductor and smooth body aluminum conductor steel reinforced ("ACSR") within the distribution system. The conductor is not safe to work on while energized, as it is brittle and at risk of failure when being handled. The condition of the conductor also puts it at an elevated risk of failure during storm conditions. Should failure occur, repairs are more challenging and additional repair time is often required, which negatively impacts reliability and cost. The program began in 2023 and is expected to take approximately ten years to complete.

***Justification***

The replacement of deteriorated conductor is justified on the obligation to maintain a safe and reliable electrical system and cannot be deferred.

***Costing Methodology***

A breakdown of the 2024 budget and proposed 2025 budget for the replacement of deteriorated conductor is provided in Table 39.

**TABLE 39**
**Proposed Capital Expenditures**
**Deteriorated Conductor Replacement Program**

| **Description** | **2023** | **2024 Budget** | **2025 Budget** |
|---|---|---|---|
| Material | $ 176,135 | $ 95,000 | $ 98,000 |
| Contractor Labour | 202,839 | 235,000 | 242,000 |
| Internal Labour and Transportation | 59,120 | 102,000 | 105,000 |
| **TOTAL** | **$ 438,094** | **$ 432,000** | **$ 445,000** |

The budget will allow for replacement of deteriorated conductor as shown in Table 40.

**TABLE 40**
**Deteriorated Conductor to be Replaced in 2025**

| Location | Line # | Facility ID Range | Spans |
|---|---|---|---|
| Upper Prince Street, Charlottetown | CO07159 | 18590 to 18599 | 17 |
| Admiral Street, Charlottetown | IK03427 | 30471 to 18363 | 18 |
| Central Street, Montague | VC02427 | 16063 to 16008 | 11 |
| Francis Street, Kensington | KN80004 | 105220 to 12381 | 2 |
| Old Summerside Road, Kensington | KN80083 | 294840 to 28182 | 16 |

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring capital requirement that is budgeted annually for the duration of the program.

***iii. Backlot Feed Relocation Program $ 489,000***

Most of Maritime Electric's distribution lines are in public rights-of-way that are accessible by on-road vehicles for overhead service. The backlot feed relocation program targets existing overhead distribution lines feeding service locations that are not accessible by on-road vehicles, or have an existing non-standard delivery point.

The presence of backlot feeds does not deter customers from installing fences, sheds, pools, septic systems, solar panels, and other items in their backyards, all of which can limit access to power lines for maintenance and power restoration. The access challenges that these installations present often require specialized equipment, increasing outage restoration times, and generally making it more difficult and costly to maintain the system at safe and reliable levels.

In addition, backlot feeds typically have an increased safety risk to the public with the possibility of children climbing trees, snowbanks, and play equipment, thereby reducing the safe distance to energized lines. These risks are also present when homeowners are performing yard maintenance, installing pools and decks, and adding storage structures.

Through the program, the Company targets projects with the greatest impact to improve public safety and system access by line crews, by removing hard to access backlot service lines and replacing them with more accessible roadside service lines. The program was initiated in 2023 and is expected to take approximately 10 years to complete.

***Justification***

The relocation of backlot feed distribution lines is justified on the obligation to maintain a safe and reliable electrical system and cannot be deferred beyond what is proposed in this Application.

***Costing Methodology***

A breakdown of the 2024 budget and proposed 2025 budget for the backlot feed relocation program is provided in Table 41.

**TABLE 41**
**Proposed Capital Expenditures**
**Backlot Feed Relocation Program**

| Description | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|
| Material | $ 176,382 | $ 143,000 | $ 147,000 |
| Contractor Labour | 139,289 | 253,000 | 261,000 |
| Internal Labour and Transportation | 38,266 | 79,000 | 81,000 |
| **TOTAL** | **$ 353,937** | **$ 475,000** | **$ 489,000** |

The budget will allow for the backlot feed relocation projects shown in Table 42.

| **TABLE 42<br>Backlot Feed Relocation Projects for 2025** | | | |
|---|---|---|---|
| **Location** | **Line #** | **Facility ID Range** | **Spans** |
| Westview Drive, Charlottetown | IK03447 | 29617 to 29663 | 4 |
| Inkerman Drive, Charlottetown | QA02722 | 31549 to 102240 | 7 |
| Moreau Drive, Charlottetown | IK03444 | 214169 to 34794 | 9 |

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring capital requirement that is budgeted annually for the duration of the program.

***d.*** **<u>Distribution Corridor Widening</u> (Recurring)** ***$ 887,000***

Under agreement with the Provincial Government, Maritime Electric is allowed to install its electrical lines at the outside edge of transportation rights-of-way. Accordingly, this also allows the Company to cut or trim vegetation in the right-of-way so that is does not contact lines; however, when the land directly adjacent to the right-of-way is treed, additional permissions are required, often from private landowners. In the past, private landowner permissions have been difficult to obtain and, therefore, many lines have significant tree stands directly next to them. Since Fiona, landowners are more aware of the risk that trees pose to power lines and there is a new opportunity to secure permissions that will allow the Company to reduce this risk by cutting trees and widening corridors.

Action 8.1 of Maritime Electric's Climate Change Adaptation Strategy ("CCAS"), provided in Appendix M, herein, describes new right-of-way widening initiatives which are being implemented in 2024. The distribution corridor widening program involves removing vegetation along existing distribution lines where it is outside of the transportation right-of-way, but in close proximity to lines. Under the program, distribution corridors selected for widening will be expanded by up to 10 feet on one, or both, side(s) of the right-of-way, where feasible.

The vegetation removal under this program will be properly budgeted as a capital expenditure on the basis that the corridor widening (including danger tree removal) will be limited to areas that have not previously been cut.[32]

Maritime Electric's existing vegetation management program, which primarily targets trees within existing transportation right-of-way limits, will be used to manage vegetation growth in the widened corridor, once it is established.

***Justification***

This program to widen distribution corridors and/or remove danger trees is justified based on the necessity to reduce tree contacts and damage to the distribution system during storms, and the obligation to provide safe and reliable service to customers.

Tree contacts are a leading cause of outages, particularly in storm events. During Dorian and Fiona, the distribution system experienced significant outages due to trees, the majority of which were located adjacent to, but outside, of the transportation right-of-way. Tree contacts can cause damage to distribution poles, transformers, and conductor, leading to longer duration outages and higher restoration costs. Distribution corridor widening is an essential new program for Maritime Electric that will protect the distribution system from damage during future storm events. Like tree removal that is required when a new distribution line is constructed, tree removal that occurs as a result of corridor widening will be capitalized. Once a corridor is widened under this program, it will then be maintained (as an operational expense) under the vegetation management program.

***Costing Methodology***

A breakdown of the 2024 budget and the proposed 2025 budget for distribution corridor widening is provided in Table 43.

[32] Danger trees are further away from lines but are still of concern due to their height.

| TABLE 43<br>Proposed Capital Expenditures<br>Distribution Corridor Widening | | |
|---|---|---|
| **Description** | **2024 Budget** | **2025 Budget** |
| Contractor Labour | $ 774,000 | $ 797,000 |
| Internal Labour and Transportation | 87,000 | 90,000 |
| **TOTAL** | **$ 861,000** | **$ 887,000** |

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is proposed as a recurring capital requirement that will be budgeted annually.

**e. Satellite-Based Vegetation Imaging – Distribution (Recurring)** ***$ 396,000***

Action 8.3 of the Company's CCAS, describes a pilot-project evaluation of satellite technology for vegetation management planning. The evaluation found the technology to be effective for providing accurate, real-time data on vegetation location and density along distribution lines.

The satellite-based vegetation imaging program involves evaluating vegetation condition, density, growth-type, and proximity to distribution infrastructure, as well as performing risk-based analysis and prioritization of vegetation management activities.

As the technology is applicable to both distribution and transmission lines, the material and labour costs of the program have been divided between the Distribution and Transmission capital budget categories.[33]

Satellite-based technology uses high-resolution, multispectral, and synthetic aperture radar data from satellite constellations, and can also incorporate aerial

33 75 per cent of the program costs have been allocated to Distribution, and 25 percent of the costs have been allocated to Transmission (see Section 6.2e, herein).

imagery from drones, helicopters, fixed-wing planes, and light detection and ranging data. In conjunction with the Company's Geographic Information System ("GIS"), this technology uses the data to inform proprietary models that analyze vegetation condition, growth, and risk factors. The technology can also measure and estimate annual growth patterns to forecast future-year requirements for vegetation management, and to help identify where future satellite scans should be focused.

***Justification***

Establishing a recurring vegetation management risk analysis and prioritization program using satellite imagery is justified based on the necessity to reduce tree contacts and related damage to the distribution system, and the obligation to provide safe and reliable service to customers. Satellite technology can effectively provide real-time data on vegetation location and density that is more accurate and efficient to collect, than comparative ground inspection data.

Tree contacts are the leading cause of outages to customers, both during non-storm and storm events. Furthermore, tree contacts can cause damage to distribution poles, transformers, and conductor, leading to longer duration outages and higher restoration costs. This risk and prioritization-based program will inform the Company's vegetation management program and the distribution corridor widening program, including the identification and removal of danger trees.[34] Targeted areas will be systematically prioritized as the highest risk, based on condition, criticality, and customer impact. This program will also ensure that both operating and capital expenditures for vegetation management are targeted in the areas that provide the most distribution system reliability benefit to customers.

[34] Vegetation management activity that occurs in existing distribution and transmission corridors is generally recorded as an operating expense. Vegetation management activity that occurs for the first time in new or expanded corridors is generally recorded as a capital expense, with all subsequent vegetation management activity recorded as an operating expense.

***Costing Methodology***

A breakdown of the proposed budget for collection and analyses of distribution system vegetation risk data is provided in Table 44.

**TABLE 44**
**Proposed Capital Expenditures**
**Satellite-Based Vegetation Imaging - Distribution**

| Description | 2025 Budget |
|---|---|
| Software Data and Vendor Labour | $ 357,000 |
| Internal Labour and Transportation | 39,000 |
| **TOTAL** | **$ 396,000** |

Supporting information for the satellite-based vegetation imaging program is provided in Confidential Appendix Q-6.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is proposed as a recurring capital requirement that will be budgeted annually.

For the first year of the program, software implementation and configuration costs will be capitalized along with satellite imagery and risk analysis costs for the entire distribution system to establish a baseline. Each subsequent year, approximately 20 per cent of the distribution system will be analyzed for vegetation management work prioritization. As such, the capital and operating costs of the program in future years will be reduced accordingly.[35]

[35] Annually recurring vendor products and services after the first year of the distribution system program are expected to cost approximately $83,000 (2024 estimate) for new satellite imagery and risk analysis (a capital expense) and $9,000 (2024 estimate) for software maintenance and support (an operating expense). Future annual costs will vary with Canada-US currency exchange rates, inflation, and supplier pricing.

## 5.6 System Meters (Recurring) *$ 805,000*

This proposed budget for system meters is to provide for the purchase and installation of revenue metering and associated equipment. A breakdown of the historical expenditures, 2024 budget and proposed 2025 budget for system meters is provided in Table 45.

**TABLE 45**
**Historical and Proposed Capital Expenditures**
**System Meters**

| Description | 2020[a] | 2021[b] | 2022 | 2023[c] | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 323,690 | $ 338,340 | $ 421,997 | $ 326,633 | $ 314,000 | $ 421,000 |
| External Labour | 172,270 | - | - | - | - | - |
| Internal Labour and Transportation | 372,174 | 292,106 | 330,687 | 311,384 | 372,000 | 384,000 |
| Other | 20,060 | 92 | 78 | 170 | - | - |
| **TOTAL** | **$ 888,194** | **$ 630,538** | **$ 752,762** | **$ 638,187** | **$ 686,000** | **$ 805,000** |

a. The 2020 approved capital budget included $300,000 for an Advanced Metering Infrastructure ("AMI") project.
b. Includes $31,696 for system meters carried over and completed in 2022.
c. Includes $18,000 for system meters carried over and to be completed in 2024.

### *Justification*

The proposed budget for system meters is justified on the obligation to serve new and existing customers and cannot be deferred.

### *Costing Methodology*

An itemized breakdown of the budget for system meters is shown in Table 46.

**TABLE 46**
**Breakdown of Proposed Budget**
**System Meters**

| Description | Materials | Internal Labour and Transportation | Budget |
|---|---|---|---|
| a. Watt Hour Meters | $ 291,000 | $ 274,000 | $ 565,000 |
| b. Combination Meters | 35,000 | 55,000 | 90,000 |
| c. Outdoor Metering Tanks | 55,000 | 55,000 | 110,000 |
| d. Miscellaneous Metering Equipment | 40,000 | - | 40,000 |
| **TOTAL** | **$ 421,000** | **$ 384,000** | **$ 805,000** |

Additional information for each of the system meters items listed in Table 46 follows.

**a. Watt-Hour Meters $ 565,000**

The budget for radio frequency ("RF") remote interrogation watt-hour meters includes a provision for new service installations, an allowance for the replacement of damaged or failed units, and the replacement of RF watt-hour meters to permit annual sample testing of approximately 500 meters, which is required to ensure compliance with Industry Canada/Measurement Canada Standards.

Table 47 provides a forecast of watt-hour meter installs in 2025 based on the anticipated rate of customer growth, historical equipment damage and failure rates, and the requirement to conduct annual compliance testing.

The budget for watt-hour meters reflects the continuation of an increased need for single phase meters and associated installation labour due to an ongoing strong demand for net metering installations. There is also a requirement for five jaw meters in the watt-hour category as these meters are needed for larger apartment buildings to step down from three phase to single phase power. These meters carry a 100 per cent premium over regular watt-hour meters.

**TABLE 47**
**Forecast of Watt-Hour Meter Installs in 2025**

| Description | Installs |
|---|---|
| Single phase – customer growth, replacements and annual testing | 1,600 |
| Network and three phase meters | 240 |
| **Total Watt-Hour Meters** | **1,840** |

The budget for watt-hour meters is based on vendor invoice information from previous years, provided in Confidential Appendix Q-7.

**b. Combination Meters $ 90,000**

The budget provides for the purchase and installation of new combination meters that measure both demand and energy consumption. New combination meters are required to meet forecast customer growth levels and to replace existing meters due to damage, failure and customer service entrance size upgrades.

In addition, the budget provides for in-situ meter installation tests (potential transformers and current transformers) to confirm accuracy. Measurement Canada recommends the testing of meter installations on an eight-year cycle.

Table 48 provides a forecast of new and replacement combination meters required in 2025.

**TABLE 48**
**Forecast of New and Replacement Combination Meters Installs in 2025**

| Description | Installs |
|---|---|
| Customer growth | 60 |
| Replacements due to upgrades, damage and failure | 5 |
| **Total Combination Meters** | **65** |

The budget for combination meters is based on vendor invoice information from previous years, provided in Confidential Appendix Q-7.

**c. Outdoor Metering Tanks $ 110,000**

Outdoor metering tanks are used in the Company's substations and in specific customer applications where customers are metered at either transmission or primary voltage levels. The budget provides for the purchase of two outdoor metering tanks and is based on vendor invoice information from previous years, provided in Confidential Appendix Q-7.

**d. Miscellaneous Metering Equipment $ 40,000**

The budget provides for the purchase of miscellaneous metering equipment such as potential transformers, current transformers, cabinets, security bands, sealing rings, locks, meter covers, load limiters, cable connectors, meter adapters, test blocks, phase indicators, neutral isolators, communication cables and media converters for interval meters, direct-current ("DC") breakers and disconnect sleeves.

***Future Commitments***

System meters is not a multi-year capital budget commitment; however, it is a recurring capital requirement that is budgeted annually.

**5.7 Distribution Equipment (Recurring) *$ 1,573,000***

The proposed budget is necessary to replace or extend the life of distribution system equipment that has failed or is deemed unsafe due to storm damage, lightning strikes, vandalism, electrical or mechanical damage, corrosion damage, technical obsolescence or performance testing.

The budget also provides for the replacement of aged system equipment that is used to provide voltage support, communications, and protection and control of the Company's assets, as well as the addition and replacement of line tools and equipment, and meter shop equipment.

System equipment that fails in service requires immediate attention as it is usually essential to the integrity and reliability of the electrical system. Therefore, a recurring investment in distribution system equipment is necessary to provide ongoing reliable service to customers.

***Justification***

The budget for distribution equipment is justified based on the need to maintain safe, reliable electrical service at the least cost and to ensure that the electrical system equipment operates as designed, to prevent catastrophic damage or injury to employees or the public. For the reasons provided, the timely replacement or life extension of aged and deteriorated distribution equipment cannot be deferred.

***Costing Methodology***

The distribution equipment budget, shown in Table 49, is based on past experience, professional engineering judgement and historical expenditures. In some cases, distribution equipment assets will only require refurbishment to extend their life while others will require a complete replacement.

| TABLE 49<br>Breakdown of Proposed Budget<br>Distribution Equipment | | | |
|---|---|---|---|
| **Description** | **Materials** | **Internal Labour and Transportation** | **Budget** |
| a. Substation, Line and Communication Equipment | $ 814,000 | $ 228,000 | $ 1,042,000 |
| b. Relay Replacement Equipment | 140,000 | 33,000 | 189,000 |
| c. Switch Replacement Equipment | 151,000 | 13,000 | 71,000 |
| d. Line Tools and Equipment | 242,000 | - | 242,000 |
| e. Meter Shop Equipment | 34,000 | - | 34,000 |
| **TOTAL** | **$ 1,299,000** | **$ 274,000** | **$ 1,573,000** |

To ensure that distribution equipment is purchased at the lowest possible costs, all material will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for the project is January 2025 with in-service dates throughout the year.

Additional information for each of the distribution equipment groupings listed in Table 49 follows.

**a. Substation, Line and Communication Equipment $ 1,042,000**

The Company operates 31 substations and approximately 6,000 km of distribution lines with equipment such as reclosers, voltage regulators, capacitor banks, power transformers and circuit breakers. The need to replace or extend the life of equipment is determined based on equipment condition, age, test results and operational history.

A breakdown of the historical expenditures, 2024 budget and proposed 2025 budget for substation, line and communication equipment is shown in Table 50. Supporting information for some proposed material costs is provided in Confidential Appendix Q-8.

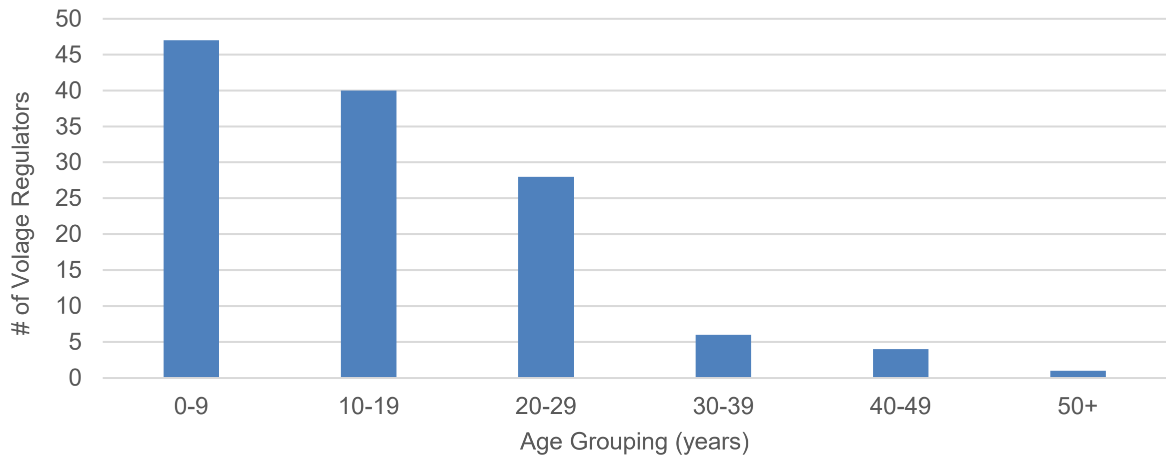
**TABLE 50**
**Historical and Proposed Capital Expenditures**
**Substation, Line and Communication Equipment**

| Description | 2020[a] | 2021[b] | 2022[c] | 2023[d] | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 657,815 | $ 884,976 | $ 757,845 | $ 628,359 | $ 794,000 | $ 814,000 |
| External Labour | 21,472 | - | - | 6,769 | - | - |
| Internal Labour and Transportation | 244,864 | 278,315 | 235,257 | 237,091 | 221,000 | 228,000 |
| Other | 15,998 | 31,315 | 38,943 | 79,457 | - | - |
| **TOTAL** | **$ 940,149** | **$ 1,194,606** | **$ 1,032,045** | **$ 951,676** | **$ 1,015,000** | **$ 1,042,000** |

a. Includes $28,001 for 2020 substation, line and communication equipment carried over and delivered in 2021.
b. Includes $192,077 for 2021 substation line and communication equipment carried over and delivered in 2022.
c. Includes $182,864 for 2022 substation line and communication equipment carried over and delivered in 2023.
d. Includes $342,000 for 2023 substation line and communication equipment to be carried over and delivered in 2024.

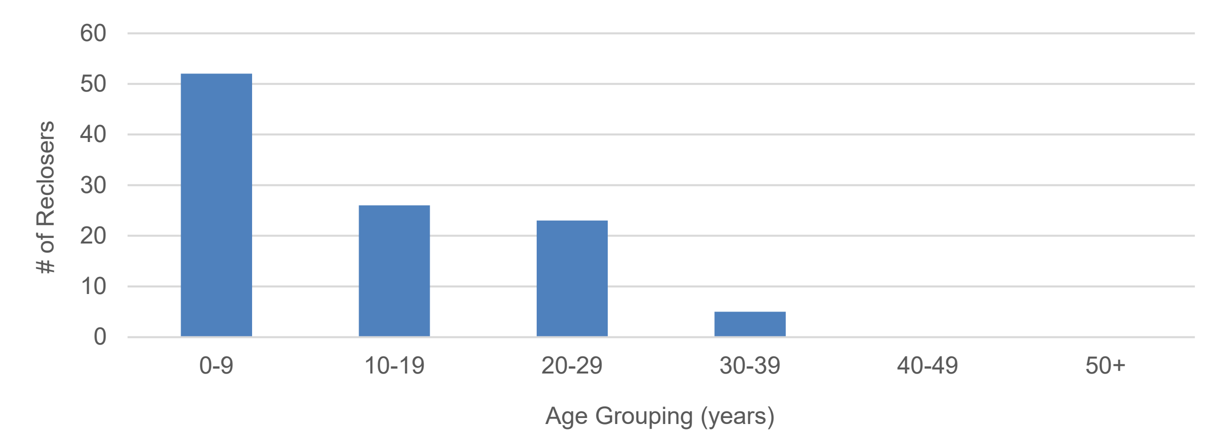
The average age of the voltage regulators in the distribution system is approximately 15 years, and approximately 4 per cent are over 40 years old as shown in Figure 9. The 0-to-9-year age grouping has the highest number of voltage regulators due to system load-growth, which required existing units to be upgraded and new units to be added.

**FIGURE 9**
**Voltage Regulators Installed in the Distribution System**




The average age of the reclosers in the distribution system is approximately 12 years, with none over 40 years old as shown in Figure 10. The 0-to-9-year age grouping has the highest number of reclosers, as the number of substations has increased during this period due to load growth, in-line reclosers have been added for reliability improvements, and oil insulated units are being phased out and replaced with more technically sophisticated, oil-free units.

**FIGURE 10**
**Reclosers Installed in the Distribution System**




The Company has 45 communication sites comprised of a 7 GHz microwave and fibre backbone system. The need to replace or extend the life of communication equipment is determined based on equipment condition, age, test results and operational history.

**b. Relay Replacement Equipment** **$ 184,000**

New generation microprocessor-based relays offer a host of advantages compared to electromechanical relays because of enhanced capabilities and programming versatility. One microprocessor-based relay replaces several electromechanical relays resulting in cost and efficiency advantages. The proposed budget is for the continued replacement and upgrade of relays.

A breakdown of the historical expenditures, 2024 budget and proposed 2025 budget for relay replacement equipment is shown in Table 51. Supporting information for the proposed material costs is provided in Confidential Appendix Q-8.

| TABLE 51<br>Historical and Proposed Capital Expenditures<br>Relay Replacement Equipment | | | | | | |
|---|---|---|---|---|---|---|
| **Description** | **2020** | **2021** | **2022[a]** | **2023** | **2024 Budget** | **2025 Budget** |
| Material | $ 109,484 | $ 172,249 | $ 113,729 | $ 164,018 | $ 136,000 | $ 151,000 |
| Internal Labour and Transportation | 68,295 | 19,500 | 42,509 | - | 32,000 | 33,000 |
| Other | - | - | 1,634 | - | - | - |
| **TOTAL** | **$ 177,779** | **$ 191,749** | **$ 157,872** | **$ 164,018** | **$ 168,000** | **$ 184,000** |

a. Includes $51,725 for 2022 relay replacement equipment carried over and delivered in 2023.

**c. Switch Replacement Equipment $ 71,000**

The requirement to replace switches is based on findings of an ongoing switch inspection program. The proposed budget also includes a provision for replacing switches that are used for bypassing recloser and voltage regulators when performing equipment upgrades. The need to replace or extend the life of switch equipment is determined on the basis of equipment condition, age, and operational history.

A breakdown of the historical expenditures, 2024 budget and proposed 2025 budget for switch replacement equipment is shown in Table 52. Supporting information for the proposed material costs is provided in Confidential Appendix Q-8.

| TABLE 52<br>Historical and Proposed Capital Expenditures<br>Switch Replacement Equipment | | | | | | |
|---|---|---|---|---|---|---|
| **Description** | **2020** | **2021** | **2022[a]** | **2023** | **2024 Budget** | **2025 Budget** |
| Material | $ 145,867 | $ 115,796 | $ 76,392 | $ 37,896 | $ 48,000 | $ 58,000 |
| Internal Labour and Transportation | 81,162 | 112,679 | 25,000 | 29,000 | 13,000 | 13,000 |
| **TOTAL** | **$ 227,029** | **$ 228,475** | **$ 101,392** | **$ 66,896** | **$ 61,000** | **$ 71,000** |

a. Includes $75,816 for 2022 switch replacement equipment carried over and delivered in 2023.

**d. Line Tools and Equipment $ 242,000**

The budget provides for the replacement of line equipment such as hotline sticks, phasing sticks, potential indicators, ground mats, hard and rubber cover-up, fall arrest equipment, survey equipment and material handling equipment such as presses and dies, running blocks and chain hoists. This is an annual recurring budget amount that is necessary to ensure worker safety and meet operational requirements.

A breakdown of the historical expenditures, 2024 budget and proposed 2025 budget for line tools and equipment is shown in Table 53.

**TABLE 53**
**Historical and Proposed Capital Expenditures**
**Line Tools and Equipment**

| Description | 2020 | 2021 | 2022[a] | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 118,953 | $ 153,936 | $ 108,706 | $ 97,639 | $ 389,000[b] | $ 242,000 |
| Other | 55,521 | 72,539 | 113,514 | 192,811 | - | - |
| **TOTAL** | **$ 174,474** | **$ 226,475** | **$ 222,220** | **$ 290,450** | **$ 389,000** | **$ 242,000** |

a. Includes $57,000 for 2022 Line Tools and Equipment carried over and delivered in 2023.
b. Includes a one-time budget requirement of $154,000 to equip the Sherbrooke and Roseneath service centres with specialty tools for repairing transmission conductor.

**e. Meter Shop Equipment $ 34,000**

The proposed budget provides for the purchase of power quality test equipment, voltmeters and meter test equipment.

A breakdown of the historical expenditures, 2024 budget and proposed 2025 budget allocation for meter shop equipment is shown in Table 54.

| TABLE 54<br>Historical and Proposed Capital Expenditures<br>Meter Shop Equipment | | | | | | |
|---|---|---|---|---|---|---|
| **Description** | **2020** | **2021[a]** | **2022[b]** | **2023** | **2024 Budget** | **2025 Budget** |
| Material | $ 22,382 | $ 20,529 | $ 24,431 | $ 14,467 | $ 33,000 | $ 34,000 |
| **TOTAL** | **$ 22,382** | **$ 20,529** | **$ 24,431** | **$ 14,467** | **$ 33,000** | **$ 34,000** |

a. Includes $18,279 for 2021 meter shop equipment carried over and delivered in 2022.
b. Includes $16,190 for 2022 meter shop equipment carried over and delivered in 2023.

***Future Commitment***

Distribution equipment is not a multi-year capital budget commitment; however, it is a recurring capital requirement that is budgeted annually.

## 5.8 Transportation Equipment (Work Support Services) *$ 3,103,000*

Maritime Electric's transportation fleet consists of large line operation vehicles with aerial and/or digger attachments, medium service trucks,[36] and smaller vehicles and equipment including cars, pick-up trucks, all-terrain vehicles ("ATV"), pole and wire trailers, and other similar items.

Line operation vehicle replacements are planned based on the age and condition of the unit. The life span of these vehicles averages from ten to twelve years with the aerial units lasting longer than the digger units. Supplier timeframes for delivery of new line operation vehicles is typically in the 18-to-24-month range; however, global supply chain delays have increased the delivery timeframe for some vehicles beyond 24 months. To better accommodate a two-to-three-year vehicle delivery schedule, the Company budgets line operation vehicles on a multi-year basis. This provides a more accurate estimate of proposed Transportation Equipment expenditures in annual capital budget applications and helps to minimize future requirements for Transportation Equipment carryovers.

Small vehicle and other equipment replacements depend on age, kilometrage and type of service; typically, the life span is five to ten years. Maritime Electric is in the process of

[36] Medium service trucks are operated with two regular eight-hour shifts per weekday.

transitioning its small vehicle fleet to plug-in hybrid electric vehicles (“PHEV”) and/or fully electric vehicles (“EV”), with individual replacement decisions based on job functions, vehicle specifications, availability, and price. Other transportation equipment requirements include trailers, ATVs and specialty equipment.

The transportation equipment purchases (by category) proposed for 2025 are shown in Table 55.

**TABLE 55**
**2025 Proposed Vehicle Procurement**

| Category | No. of Units |
|---|---|
| Line Operation Vehicles – Year 1 Purchase | 1 |
| Line Operation Vehicles – Year 2 Purchase | 3 |
| Small Vehicles and Equipment | 12 |
| **TOTAL** | **16** |

***Justification***

Maritime Electric’s vehicle replacement criteria are shown in Table 56.

**TABLE 56**
**Maritime Electric Replacement Criteria for Vehicles**

| | |
|---|---|
| Heavy Line Operation Vehicles | 10 years or 250,000 kilometres (“km”) |
| Heavy/Medium Flat Bed Trucks | 10 years or 250,000 kilometres (“km”) |
| Medium Service Trucks | 5 years or 250,000 kilometres (“km”) |
| Passenger Vehicles | 7 years or 250,000 kilometres (“km”) |
| Tracked Heavy Vehicles | 15 years |

To determine if a vehicle has reached the end of useful service life, the age of the vehicle is considered along with additional criteria such as annual maintenance costs, power take-off hours (if applicable) and vehicle condition (e.g., rust, electrical issues, etc.)

Based on all criteria considerations, vehicles proposed for replacement in this Application will reach the end of their useful service life in 2025.

The timely replacement of aged and deteriorated transportation equipment is justified to protect the safety of employees and the public, and to fulfil the obligation to provide reliable service to customers at least cost.

***Costing Methodology***

A breakdown of the historical expenditures, 2024 budget and proposed 2025 budget for transportation equipment is shown in Table 57.

**TABLE 57**
**Historical and Proposed Capital Expenditures**
**Transportation Equipment**

| Description | 2020[a] | 2021[b] | 2022[c] | 2023[d] | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material and External Labour | $ 1,757,895 | $ 1,788,798 | $ 1,947,922 | $ 1,591,332 | $ 2,587,000 | $ 2,959,000 |
| Internal Labour and Transportation | 36,586 | 51,568 | 79,204 | 90,899 | 87,000 | 144,000 |
| Other | 7,489 | 2,934 | 82 | 3,075 | - | - |
| **TOTAL** | **$ 1,801,970** | **$ 1,843,300** | **$ 2,027,208** | **$ 1,685,306** | **$ 2,674,000** | **$ 3,103,000** |

a. Includes $316,674 in 2021 costs and $704,789 in 2022 costs for 2020 transportation equipment carried over and delivered in 2021 and 2022.
b. Includes $1,409,300 in 2021, 2022 and 2023 actual costs and $434,000 budgeted for 2021 transportation equipment carried over to be delivered in 2024.
c. Includes $785,208 in 2022 and 2023 actual costs and $1,242,000 budgeted for 2022 transportation equipment carried over to be delivered in 2024.
d. Includes $427,306 in 2023 actual costs and $1,258,000 budgeted for 2023 transportation equipment carried over to be delivered in 2024.

The budget is based on a combination of vendor quotes, professional engineering estimates, and vendor invoice information from prior years for similar items. A breakdown of the budget for transportation equipment replacements and additions in 2025, along with the 2024 budget and the 2026 forecast, is shown in Table 58.

| TABLE 58<br>Breakdown of Proposed Budget<br>Transportation Equipment | | | | |
|---|---|---|---|---|
| **Description** | **2024** | **2025 Original[a]** | **2025 Revised** | **2026[b]** |
| a. Line Operation Vehicles | $ 2,144,000 | $ 1,366,000 | $ 1,663,000 | $ 446,000 |
| b. Small Vehicles and Equipment | 530,000 | 1,104,000 | 1,440,000 | - |
| **TOTAL** | **$ 2,674,000** | **$ 2,470,000** | **$ 3,103,000** | **$ 446,000** |

a. The original 2025 budget was provided in Table 54 of the 2024 Capital Budget Application.
b. Does not include the budget amount for transportation equipment that will be initiated in the 2026 Capital Budget Application.

To ensure that transportation equipment is purchased at the lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

Additional information on the transportation equipment items listed in Table 58 follows.

**a. <u>Line Operation Vehicles</u> $ 1,663,000**

Three line operation vehicles that were approved with the 2024 Capital Budget (see Table 59) will be received in 2025, and the addition of one new aerial bucket line operation vehicle, required to meet operation requirements, will be ordered in 2025 for delivery in 2026 (see Table 60).

| TABLE 59<br>Line Operations Vehicles - Year 2 of Procurement | | | |
|---|---|---|---|
| | **Aerial Bucket Truck Central District** | **Digger/Derrick Truck Central District** | **Aerial Bucket Truck Western District** |
| **Item** | **Replacement Vehicles** | | **New Vehicles** |
| Vehicle # | 15-12-80 | 14-12-74 | New |
| Chassis Make/Model | Freightliner | Dodge 5500 | Freightliner |
| Boom Make/Model | Possi+ 55' aerial bucket | Altec 50' digger/derrick | Posi+ 55' aerial bucket |
| Description | Chassis and aerial device are a 2015 model. Aerial device is a 55' single person aerial bucket truck | Chassis and boom are 2014 model. Unit is a 50' digger/derrick truck. | Chassis and 55' aerial device. Single person aerial bucket truck. |
| Odometer as of January 2024 | 172,147 km | 134,296 km | - |
| Power Take Off or Engine Hours | 13, 339 engine hours | 8,919 engine hours | - |
| Approximate Maintenance Costs Over Past 3 Years | $114,000 | $72,000 | - |
| Summary | The chassis will be 10 years old at time of replacement and is starting to show signs of age, with increased maintenance costs and down time. | The chassis will be 11 years old at time of replacement and is starting to show signs of age, with increase maintenance costs and down time. | New aerial bucket truck required in the Western District to support a new line crew. |

| TABLE 60<br>Line Operations Vehicles – Year 1 Purchases | |
|---|---|
| **Item** | **Aerial Bucket Truck Eastern District** |
| Vehicle # | New |
| Chassis Make/Model | Freightliner (or equivalent) |
| Boom Make/Model | Posi+ 55' Aerial Budget (or equivalent) |
| Description | Chassis and 55' aerial device. Single person aerial bucket truck. |
| Summary | New aerial bucket truck required in the Central District to support a new line crew. |

Table 61 provides a multi-year breakdown of the proposed line operation vehicle purchases to be initiated and completed in 2025.

**TABLE 61**
**Line Operation Vehicles Budget**

| | Description | Location | Age (years) | Current Odometer (km) | 2024 (A) | 2025 Original (B) | 2025 Revised (C) | 2026 Budget (D) | Multi-Year Budget (E=A+C+D) |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Aerial Bucket (500 Series) | Western Line | - | - | $ 206,000 | $ 414,000 | $ 457,500 | $ - | $ 663,500 |
| 2. | Aerial Bucket (500 Series) | Central Line | 10 | 172,147 | 206,000 | 414,000 | 457,500 | - | 663,500 |
| 3. | Digger/Derrick Truck | Central Line | 11 | 134,296 | 176,000 | 538,000 | 528,000 | - | 704,000 |
| 4. | Aerial Bucket (500 Series) | Eastern Line | - | - | - | - | 220,000 | 456,000 | 676,000 |
| **TOTAL** | | | | | **$ 588,000**[a] | **$1,366,000**[b] | **$1,663,000** | **$ 456,000**[c] | **$ 2,707,000** |

a. Does not include the budget amount for line operation vehicle purchases that were initiated in the 2023 Capital Budget Application.
b. Does not include the budget amount for line operation vehicle purchases initiated in this Application.
c. Does not include the budget amount for line operation vehicle purchases that will be initiated in the 2026 Capital Budget Application.

Supporting information for line operation vehicle cost estimates is provided in Confidential Appendix Q-9.

**b. Small Vehicles and Equipment** **$ 1,440,000**

The replacement of seven existing passenger vehicles and one ATV is planned for 2025. New additions include two passenger vehicles, one pole trailer, and one underground cable puller. The existing vehicles meet Maritime Electric's criteria for passenger vehicles replacement, which identifies seven years or 200,000 km as the criteria. The two additional passenger vehicles are required for new operational positions. The new pole trailer and underground cable puller are necessary to meet new and existing customer requirements for service connections and upgrades, respectively.

Table 62 provides a breakdown of the proposed small vehicle and other equipment replacements and additions.

| TABLE 62<br>Proposed Transportation Equipment Replacements and Additions for 2025 | | | | | |
|---|---|---|---|---|---|
| | **Description** | **Location** | **Age (years)** | **Current Odometer (km)** | **2025** |
| 1. | 1/4 Ton Truck | Vegetation Management | 7 | 118,146 | $ 64,000 |
| 2. | 1/2 Ton Truck | Survey | - | - | 84,000 |
| 3. | 1/2 Ton Truck | Survey | 7 | 229,760 | 84,000 |
| 4. | 1/2 Ton Truck[a] | Survey | 7 | 138,068 | 91,000 |
| 5. | 1/2 Ton Truck[a] | Central Line | 7 | 163,000 | 91,000 |
| 6. | 3/4 Ton Truck | Tech Services | 7 | 72,942 | 104,000 |
| 7. | 3/4 Ton Truck | Tech Services | 7 | 110,757 | 104,000 |
| 8. | Small Passenger Vehicle[a] | Operations Support | - | - | 64,000 |
| 9. | Small Passenger Vehicle[a] | Meter Reading | 6 | 207,515 | 64,000 |
| 10. | Pole Trailer | Central Line | - | - | 52,000 |
| 11. | Side-by-Side ATV with Trailer | T&D Operations | 12 | - | 84,000 |
| 12. | Underground Cable Puller | - | - | - | 454,000 |
| 13. | Allowance for unforeseen capital expenditures | | | | 100,000 |
| **TOTAL** | | | | | **$ 1,440,000** |

a. Planned to be sourced as a PHEV, if available.

Supporting information for small vehicles and equipment cost estimates is provided in Confidential Appendix Q-9.

***Future Commitments***

Transportation equipment is a recurring capital requirement that is budgeted annually. The purchase of the aerial bucket line operation vehicle to be initiated in 2025 is a multi-year capital budget commitment that will be completed over two years, in 2025 and 2026. If there are any changes to the evidence provided herein including changes in scope, budget or timelines for this vehicle over the course of year one, further evidence will be provided in the 2026 Capital Budget Application.

## 6.0 TRANSMISSION $ 27,032,000

The Transmission category reflects the Company's proposed activities for the expansion and replacement of 69 kV (T-line) and 138 kV (Y-line) transmission system components using the Company's ISP as a guideline. This includes transmission lines, substations, power transformers and protection devices such as circuit breakers.

### 6.1 Substation Projects $ 19,565,000

The proposed budget allocation for substation projects is shown in Table 63.

**TABLE 63**
**Breakdown of Proposed Budget**
**Substation Projects**

| Description | Budget |
|---|---|
| a. Woodstock Switching Station | $ 5,161,000 |
| b. Lorne Valley Switching Station Expansion | 2,221,000 |
| c. Sherbrooke X1 Autotransformer Replacement | 3,184,000 |
| d. West Royalty Substation 13.8 kV Distribution Replacements | 1,777,000 |
| e. Scotchfort Substation | 872,000 |
| f. Charlottetown Grid Modernization | 200,000 |
| g. Power Transformers | 3,943,000 |
| h. Substation Oil Containment Program | 176,000 |
| i. Substation Modernization Program | 560,000 |
| j. 138 kV Breaker Replacement Program | 146,000 |
| k. Communication Fibre – Church Road to Souris | 1,279,000 |
| l. Fibre Modifications Due to Road Alterations | 46,000 |
| **TOTAL** | **$ 19,565,000** |

**a. Woodstock Switching Station (Justifiable) $ 5,161,000**

This will be the third year of the Woodstock switching station project that was fully described as a multi-year project in the 2023 Capital Budget Application.

The project work plan for 2025 includes ordering and installing the steel structures on the 138 kV side of the station, completing and installing the cybersecurity and protection and control panels in the control building, installing all 138 kV and 69 kV high-voltage equipment and bus work and ordering/installing the balance of the substation equipment. Once the autotransformer is received and installed, the equipment wiring and commissioning will start. Finally, when the installation of the control fibre and the transmission lines into the station is complete, the transmission lines will be connected. It is expected that the switching station will be fully commissioned and energized by the end of 2025.

### *Justification*

The project is justifed based on the need to improve voltage support and reliability for customers in western PEI and cannot be deferred.

### *Costing Methodology*

A breakdown of the budget for the Woodstock Switching Station project is provided in Table 64. A contingency has been budgeted as some major components were estimated and to allow for minor adjustments to the project scope of work. As new information on costs becomes available, the contingency will be used accordingly.

**TABLE 64**
**Breakdown of Multi-Year Budget**
**Woodstock Switching Station**

| Description | 2023 (A) | 2024 Original | 2024 Revised (B) | 2025 Original | 2025 Revised (C) | Budget[a] (D=A+B+C) |
|---|---|---|---|---|---|---|
| Civil Works | $ 1,469,000 | $ 2,270,000 | $ 2,792,000 | $ - | $ - | $ 4,261,000 |
| Switching Station Equipment | - | 1,214,000 | 1,231,000 | 561,000 | 754,000 | 1,985,000 |
| Control Building and Station Service Equipment | - | 587,000 | 605,000 | 801,000 | 851,000 | 1,456,000 |
| Autotransformer Equipment | - | 481,000 | 1,641,000 | 2,116,000 | 1,823,000 | 3,464,000 |
| Structural Steel | - | 754,000 | 754,000 | 777,000 | 777,000 | 1,531,000 |
| High Voltage Bus Works | - | - | - | 543,000 | 518,000 | 518,000 |
| Engineering Design | 150,000 | - | - | - | - | 150,000 |
| Internal Labour and Transportation | 59,000 | 311,000 | 312,000 | 285,000 | 285,000 | 656,000 |
| Contingency (5 per cent)[b] | 63,000 | 406,000 | 334,000 | 1,125,000 | 153,000 | 550,000 |
| **TOTAL** | **$ 1,741,000** | **$ 6,023,000** | **$ 7,669,000** | **$ 6,208,000** | **$ 5,161,000** | **$14,571,000** |

a. Total budget is unchanged from that provided in the 2024 Capital Budget Application.
b. The original multi-year project budget had a total contingency of $1,594,000. As the project progresses, the contingency amount is being reduced to offset pricing increases.

With an increase of $1,646,000 in 2024 and a reduction of $1,047,000 in 2025, there is a resultant net increase of $599,000 to the project budget that was originally included in the 2023 Capital Budget Application. This is due to cost increases associated with the power transformer and substation equipment, as well as additional civil works determined to be necessary during the preliminary design layout stages. Also, due to the timing of power transformer progress payment requirements, there has been a shifting of some costs previously budgeted for 2025 to 2024.

Supporting information for the cost estimates in Table 64 is provided in Confidential Appendix Q-10.

The Woodstock switching station is interdependent with transmission line modifications in the 2025 Capital Budget Application. The transmission line modifications will connect the new switching station to the existing transmission system. The combined budget of the two interdependent projects is shown in Table 65.

**TABLE 65**
**Combined Budget of Interdependent Projects**

| Description | 2023 (A) | 2024 (B) | 2025 (C) | Budget (D=A+B+C) |
|---|---|---|---|---|
| Woodstock Switching Station | $ 1,741,000 | $ 7,669,000 | $ 5,161,000 | $14,571,000 |
| Woodstock Transmission Line Modifications[a] | - | - | 1,000,000 | 1,000,000 |
| **TOTAL** | **$ 1,741,000** | **$ 7,669,000** | **$ 6,161,000** | **$15,571,000** |

a. Woodstock transmission line modifications were originally planned for 2024 in the 2023 Capital Budget Application; however, to better align with the completion of other planned work at the site, the project was deferred to 2025 and is discussed in Section 6.2c and Appendix N, herein.

To ensure this project is completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The project was started in March 2023 and is scheduled to be completed in the fourth quarter of 2025.

***Alternatives***

As the project is currently underway, there are no alternatives to completing the project as planned.

***Future Commitments***

This is a multi-year project that will be completed over three years, from 2023 to 2025.

**b. <u>Lorne Valley Switching Station Expansion</u> (Justifiable) $ 2,221,000**

This will be the second year of the Lorne Valley switching station expansion project that was fully described as a multi-year project in the 2024 Capital Budget Application.

The project work plan for 2025 includes completion of engineering design and a 50 per cent progress payment on the autotransformer.

***Justification***

The expansion of the Lorne Valley switching station is justified based on the obligation to provide safe and reliable service to customers. More specifically, project benefits will include: enabling existing autotransformers in the West Royalty substation to be offloaded; improving system reliability in central and eastern PEI; extending the yearly period during which other critical system components can be taken out of service for maintenance; and reducing the potential for customer outages when an unplanned transmission outage occurs.

***Costing Methodology***

A breakdown of the budget for the Lorne Valley switching station expansion project is provided in Table 66. A contingency has been budgeted as some major components were estimated and to allow for minor adjustments to the project scope of work. As a new information on costs becomes available, the contingency will be used accordingly.

| TABLE 66<br>Breakdown of Multi-Year Budget<br>Lorne Valley Switching Station Expansion | | | | | | |
|---|---|---|---|---|---|---|
| **Description** | **2024 (A)** | **2025 Original** | **2025 Revised (B)** | **2026 Original** | **2026 Revised (C)** | **Budget[a] (D=A+B+C)** |
| Civil Works | $ - | $ - | $ - | $ 865,000 | $ 907,000 | $ 907,000 |
| Switching Station Equipment | - | - | - | 316,000 | 875,000 | 875,000 |
| Control Building and Station Service Equipment | - | - | - | 322,000 | 318,000 | 318,000 |
| Autotransformer Equipment | - | 1,690,000 | 1,690,000 | 1,915,000 | 1,915,000 | 3,605,000 |
| Structural Steel | - | - | - | 400,000 | 400,000 | 400,000 |
| High Voltage Bus Works | - | - | - | 227,000 | 227,000 | 227,000 |
| Engineering Design | 50,000 | 100,000 | 100,000 | - | - | 150,000 |
| Internal Labour and Transportation | 35,000 | 141,000 | 141,000 | 147,000 | 147,000 | 323,000 |
| Contingency (15 per cent)[b] | 13,000 | 290,000 | 290,000 | 628,000 | 31,000 | 334,000 |
| **TOTAL** | **$ 98,000** | **$ 2,221,000** | **$ 2,221,000** | **$ 4,820,000** | **$ 4,820,000** | **$ 7,139,000** |

a. Total budget is unchanged from that provided in the 2024 Capital Budget Application.
b. The original multi-year project budget had a total contingency of $931,000. As the project progresses, the contingency amount is being reduced to offset pricing increases.

Supporting information for the costs estimates in Table 66 is provided in Confidential Appendix Q-11.

The Lorne Valley switching station expansion is interdependent with the Y-106 Scotchfort to Lorne Valley transmission line project,[37] and the Lorne Valley transmission modifications project, with the latter to be included in the 2026 Capital Budget Application. The upgraded transmission line and associated modifications will connect the expanded Lorne Valley switching station to the existing 138 kV transmission system. The combined budget of the three interdependent projects is shown in Table 67.

[37] Y-106 Scotchfort to Lorne Valley transmission line project is discussed in Section 6.2c and Appendix N, herein.

| TABLE 67<br>Combined Budget of Interdependent Projects | | | | |
|---|---|---|---|---|
| Description | 2024<br>(A) | 2025<br>(B) | 2026<br>(C) | Budget<br>(D=A+B+C) |
| Lorne Valley Switching Station Expansion | $ 98,000 | $ 2,221,000 | $ 4,820,000 | $ 7,139,000 |
| Y-106 Scotchfort to Lorne Valley Transmission Line | 182,000 | 3,192,000 | 1,707,000 | 5,081,000 |
| Lorne Valley Transmission Line Modifications | - | - | 574,000 | 640,000 |
| **TOTAL** | **$ 280,000** | **$ 5,413,000** | **$ 7,101,000** | **$ 12,794,000** |

To ensure this project is completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for the project is January 2024 with a completion date in the fourth quarter of 2026.

***Alternatives***

As this project is currently underway, there are no alternatives to completing this project as planned.

***Future Commitments***

This is a multi-year project that will be completed over three years, from 2024 to 2026. If there are any changes to the evidence provided herein, including changes in scope, budget or timelines subsequent to approval, further evidence will be provided in the 2026 Capital Budget Application.

**c. <u>Sherbrooke X1 Autotransformer Replacement</u> (Justifiable) $ 3,184,000**

This will be the second year of the Sherbrooke X1 autotransformer replacement project that was fully described as a multi-year project in the 2024 Capital Budget Application.

The project work plan for 2025 includes ordering long-lead equipment, civil and structural works, and station control upgrades.

***Justification***

The project is justified based on the need to replace a critical aged asset that has reached end of life and cannot be operated to failure. For these reasons, it cannot be deferred.

***Costing Methodology***

A breakdown of the budget for the Sherbrooke X1 autotransformer replacement project is provided in Table 68. A contingency has been budgeted as some major components were estimated and to allow for minor adjustments to the project scope of work. As new information on costs become available, the contingency will be used accordingly.

**TABLE 68**
**Breakdown of Multi-Year Budget**
**Sherbrooke X1 Autotransformer Replacement**

| Description | 2024 (A) | 2025 Original | 2025 Revised (B) | 2026 Original (C) | Budget[a] (D=A+B+C) |
|---|---|---|---|---|---|
| Civil Works | $ - | $ 235,000 | $ 398,000 | $ - | $ 398,000 |
| Switching Station Equipment | - | 384,000 | 533,000 | - | 533,000 |
| Control Building and Station Service Equipment | - | 144,000 | 144,000 | - | 144,000 |
| Autotransformer Equipment | - | 1,859,000 | 1,859,000 | 1,741,000 | 3,600,000 |
| Structural Steel | - | 52,000 | 52,000 | - | 52,000 |
| High Voltage Bus Works | - | 57,000 | 57,000 | - | 57,000 |
| Engineering Design | 80,000 | - | - | - | 80,000 |
| Internal Labour and Transportation | 30,000 | 38,000 | 39,000 | 51,000 | 120,000 |
| Contingency (15 per cent)[b] | 16,000 | 415,000 | 102,000 | 269,000 | 387,000 |
| **TOTAL** | **$ 126,000** | **$ 3,184,000** | **$ 3,184,000** | **$ 2,061,000** | **$ 5,371,000** |

a. Total budget is unchanged from that presented in the 2024 Capital Budget Application.
b. The original multi-year project budget had a total contingency of $700,000. As the project progresses, the contingency amount is being reduced to offset pricing increases.

Supporting information for the cost estimates in Table 68 is provided in Confidential Appendix Q-12.

The Sherbrooke X1 autotransformer replacement project is interdependent with Sherbrooke switching station transmission modifications that will be included in the 2026 Capital Budget Application. The transmission line modifications will connect the new autotransformer with the existing transmission system. The combined budget of the two interdependent projects is shown in Table 69.

**TABLE 69**
**Combined Budget of Interdependent Projects**

| Description | 2024 (A) | 2025 (B) | 2026 (C) | Budget (D=A+B+C) |
|---|---|---|---|---|
| Sherbrooke X1 Autotransformer Replacement | $ 126,000 | $ 3,184,000 | $ 2,061,000 | $ 5,371,000 |
| Sherbrooke Switching Station Transmission Modifications | - | - | 640,000 | 640,000 |
| **TOTAL** | **$ 126,000** | **$ 3,184,000** | **$ 2,701,000** | **$ 6,011,000** |

To ensure this project is completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for the project is January 2024 with a completion date in the fourth quarter of 2026.

***Alternatives***

There is no alternative to replacing Sherbrooke X1 autotransformer.

***Future Commitments***

This is a multi-year project that will be completed over three years from 2024 to 2026. If there are any changes to the evidence provided herein, including changes in scope, budget or timelines subsequent to approval, further evidence will be provided in the 2026 Capital Budget Application.

**d. West Royalty Substation 13.8 kV Distribution Replacements (Justifiable) $ 1,777,000**

The West Royalty substation is located at 30 Sherwood Road, Charlottetown and serves about 60 per cent of Island loads. The substation includes a 138 kV bus (supplied by Y-109, Y-111, and Y-102), a 69 kV bus (to supply T-1, T-13, and T-15), a 25 kV distribution system, and a 13.8 kV distribution system.

The West Royalty substation 13.8 kV distribution system was built in the 1970s and is approaching the end of life. This distribution system serves 7,503 customers (as of March 2024) and provides backup power supply for other 13.8 kV circuits in the Charlottetown area.

This project involves replacing and upgrading the entire 13.8 kV distribution system at the West Royalty substation. The objective is to replace critical equipment that is at elevated risk of failure due to age, while increasing the capacity and resiliency of the system. This will include the addition of two new 69 kV circuit breakers, the replacement and upgrading of both 69 kV/13.8 kV 20 megavolt ampere ("MVA") power transformers to 30 MVA, and the installation of new switchgear and underground circuit exits from the substation.

The addition of two new circuit breakers will decrease the probability of interruptions on the T-1, T-13, and T-15 transmission lines, as each transformer will have a designated breaker for more isolated protection. Increasing the size of the transformers and upgrading the switchgear will help accommodate growing customer load while allowing for flexibility and expansion into the future.

***Justification***

The 13.8 kV West Royalty substation distribution system has two 20 MVA power transformers (X1 and X4) and one 13.8 kV switchgear feeding five 13.8 kV distribution circuits including Inkerman, Sherwood, Queens Arms, Mount Edward, and University Avenue. Both of these power transformers have reached end of life and require placement. Also, to provide accommodation for future load growth and to increase the ability to transfer load from adjacent substations, it is required that the size of both these transformers is increased to 30 MVA.

The switchgear, underground cables, and related terminations have also reached the end of life, with increasing failures and difficulty to repair. The switchgear is limited in its ability to be reconfigured in the event of a major failure or to accommodate additional circuits as load continues to grow. The terminations and underground cables are paper insulated lead sheath type, which is outdated technology and costly to repair, as the resources capable of performing repairs are not readily available.

***Costing Methodology***

A breakdown of the budget for the West Royalty substation 13.8 kV distribution replacements project is provided in Table 70. A contingency has been budgeted as some major components were estimated and to allow for minor adjustments to the project scope of work. As new information on costs become available, the contingency will be used accordingly.

| TABLE 70<br>West Royalty Substation 13.8 kV Distribution Replacements Budget | | | | |
|---|---|---|---|---|
| **Description** | **2025<br>(A)** | **2026<br>(B)** | **2027<br>(C)** | **Budget<br>(D = A + B + C)** |
| Civil Works | $ - | $ 992,000 | $ - | $ 992,000 |
| Switching Station Equipment | 288,000 | 133,000 | 2,495,000 | 2,916,000 |
| Control Building and Station Service Equipment | - | 144,000 | - | 144,000 |
| Power Transformer Equipment | 1,042,000 | 1,610,000 | 2,940,000 | 5,592,000 |
| Structural Steel | - | 100,000 | - | 100,000 |
| High Voltage Bus Works | - | 599,000 | - | 599,000 |
| Engineering Design (estimate) | 80,000 | - | - | 80,000 |
| External Labour (estimate) | - | - | 70,000 | 70,000 |
| Internal Labour and Transportation | 135,000 | 142,000 | 251,000 | 528,000 |
| Contingency (15 per cent)[a] | 232,000 | 558,000 | 863,000 | 1,653,000 |
| **TOTAL** | **$ 1,777,000** | **$ 4,278,000** | **$ 6,619,000** | **$ 12,674,000** |

a. The contingency is calculated from the Budget column. As the project progresses, the contingency amount will be reduced to offset pricing increases, if necessary.

Supporting information for the cost estimates in Table 70 is provided in Confidential Appendix Q-13.

To ensure this project is completed at lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for the project is January 2025 with a completion date in the fourth quarter of 2027.

***Alternatives***

There is no alternative to replacing the West Royalty substation 13.8 kV distribution system.

***Future Commitments***

This is a multi-year project that will be completed over three years from 2025 to 2027. If there are any changes to the evidence provided herein, including changes in scope, budget or timelines subsequent to approval, further evidence will be provided in the 2026 and/or 2027 Capital Budget Application(s).

**e. <u>Scotchfort Substation</u> (Justifiable) $ 872,000**

The project involves the construction of a new substation in the Scotchfort area. The new substation will serve two purposes, one will be as a distribution substation, supplying customers from the existing Scotchfort substation after it is retired, and the other will be as a 138 kV switching station for transmission lines Y-104, Y-106, Y-114 and the Y-119 extension to Scotchfort, with the Y-119 extension described in Section 6.2c and Appendix N, herein.

The Y-119 Extension to Scotchfort project needs to be connected to a switching location. West Royalty substation was considered; however, this option was dismissed for the following reasons:

- The addition of a third line to the West Royalty substation is challenging due to physical constraints and would require significant substation modifications;
- The addition of a third line to the West Royalty substation would increase the reliance on this substation. The establishment of a new substation in Scotchfort will provide geographic supply diversity for Maritime Electric customers living in central and eastern PEI, which represent approximately 73 per cent of the Company's customer base; and
- The addition of a third line to the West Royalty substation would not alleviate other system concerns, the most significant of which is the overloading of transmission line T-2 with the loss of line Y-102.

The preferred alternative to West Royalty substation is for the Company to configure the Scotchfort substation to service as a switching location for the Y-119 extension, in addition to being a replacement for the existing Scotchfort substation, which does not meet currently safety standards and is at end of life.

The new Scotchfort substation will be constructed at a yet to be determined location in the Scotchfort area. Consideration was given to constructing the substation in the same location as the existing Scotchfort substation; however, this option was not reasonable due to the small physical size of the land parcel. Future system needs for the existing Scotchfort substation land parcel is currently under consideration.

The new Scotchfort substation will be designed to connect four transmission lines, with consideration for future expansion should it be required. The substation will include a 10 MVA, 138/12.5 kV power transformer with three feeders, as well as provisions for a fourth feeder, which will be added in the future as loading and reliability improvement requirements arise. The Company is proposing to combine the distribution substation replacement and transmission switching yard requirements into one project, to realize the construction and cost efficiencies cost associated with doing so.

The work plan for the Scotchfort substation is as follows:

***Year 1 (2025)***

The land purchase process, including surveys, site tests, and permitting will be completed in early 2025. Engineering design will be completed during the spring and summer of 2025, and tendering for the power transformer will be completed near the end of the year.

***Year 2 (2026)***

Long lead time equipment will be tendered in early 2026, as well as the supply and installation of structural steel. The substation yard civil and earthworks will begin in the spring of 2026 with site clearing, backfill, grading, and foundations. This will be followed with the installation of ground grid, cable trench, fencing, conduits, and the oil containment system for the power transformer. The construction of the control building will be on-going throughout this timeframe and will continue into the fall of 2026. Structural steel erection and the construction of cybersecurity and protection and control ("P&C") panels will occur from the fall until end of the year.

***Year 3 (2027)***

The remaining substation equipment will be ordered in early 2027. The cybersecurity and P&C panels will then be completed and installed in the control building. All high voltage equipment and bus work will also be installed along with the grounding, back-up generator and security cameras. Finally, high voltage circuit breakers and power transformer will be installed and commissioned, the installation of the control fibre and the transmission lines into the station will be completed, and the transmission lines will be connected. The substation will be energized by the end of 2027.

***Justification***

The completion of the new Scotchfort substation, with associated transmission infrastructure, is justified based on the obligation to provide safe and reliable service to customers. More specifically, project benefits include the replacement of the existing Scotchfort substation which is at end of life, improvement of system reliability in central and eastern PEI, and reduction of potential for significant customer outages when unplanned transmission line outages occur.

***Costing Methodology***

A breakdown of the budget for the Scotchfort substation project is provided in Table 71. A contingency has been budgeted as some major components were estimated and to allow for minor adjustments to the project scope of work. As new information on costs become available, the contingency will be used accordingly.

| TABLE 71<br>Breakdown of Multi-Year Budget<br>Scotchfort Substation | | | | |
|---|---|---|---|---|
| **Description** | **2025 (A)** | **2026 (B)** | **2027 (C)** | **Budget (D=A+B+C)** |
| Civil Works | $ - | $ 5,035,000 | $ - | $ 5,035,000 |
| Substation Equipment | - | 1,353,000 | 2,587,000 | 3,940,000 |
| Building, Panels, Security and Wiring | - | 660,000 | 680,000 | 1,340,000 |
| High Voltage Buswork | - | - | 812,000 | 812,000 |
| Structural Steel | - | 751,000 | 773,000 | 1,524,000 |
| Land (estimate) | 300,000 | - | - | 300,000 |
| Engineering Design (estimate) | 250,000 | - | - | 250,000 |
| Fibre in Lane (1 km) | - | - | 30,000 | 30,000 |
| Internal Labour and Transportation | 208,000 | 379,000 | 263,000 | 850,000 |
| Contingency (15 per cent)[a] | 114,000 | 1,227,000 | 772,000 | 2,113,000 |
| **TOTAL** | **$ 872,000** | **$ 9,405,000** | **$ 5,917,000** | **$16,194,000** |

a. The contingency is calculated from the Budget column. As the project progresses, the contingency amount will be reduced to offset pricing increases, if necessary.

Supporting information for the cost estimates in Table 71 is provided in Confidential Appendix Q-14.

The Scotchfort substation project is interdependent with the Y-119 Extension to Scotchfort transmission line project, as described in Section 6.2c and Appendix N, the Y-109 Bedeque to Bannockburn Road rebuild project, and the Scotchfort substation transmission modifications project. The latter two projects will be included in the 2027 Capital Budget Application. These transmission line projects will connect the new Scotchfort substation to the Bedeque switching station. The combined budget of the four interdependent projects is shown in Table 72.

| TABLE 72<br>Combined Budget of Interdependent Projects | | | | | |
|---|---|---|---|---|---|
| **Description** | **2025 (A)** | **2026 (B)** | **2027 (C)** | **2028 (D)** | **Budget (E=A+B+C+D)** |
| Scotchfort Substation | $ 872,000 | $ 9,405,000 | $ 5,917,000 | $ - | $ 16,194,000 |
| Y-119 Extension to Scotchfort | 545,000 | 4,032,000 | 4,071,000 | 4,240,000 | 12,888,000 |
| Y-109 Rebuild | - | - | 5,045,000 | 5,226,000 | 10,271,000 |
| Scotchfort Substation Transmission Modifications | - | - | 421,000 | - | 421,000 |
| **TOTAL** | **$ 1,417,000** | **$ 13,437,000** | **$ 15,454,000** | **$ 9,466,000** | **$ 39,774,000** |

To ensure this project is completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for the project is January 2025 with a completion date in the fourth quarter of 2027.

***Alternatives***

The only alternative is to defer the project and the associated Y-119 Extension to Scotchfort project. However, as discussed in the Y-119 Extension project description included in Appendix N, herein, deferral would result in increased energy costs for customers. Also, a deferral would not address the existing Scotchfort substation which is at end of life. For these reasons, deferral is not recommended, as the prudent approach is to proceed with the project, as planned.

***Future Commitments***

This is a multi-year project that will be completed over three years, from 2025 to 2027. If there are any changes to the evidence provided herein, including changes in scope, budget or timelines subsequent to approval, further evidence will be provided in the 2026 and/or 2027 Capital Budget Application(s).

**f. Charlottetown Grid Modernization (Justifiable) $ 200,000**

The Charlottetown Grid Modernization Pilot Project will be implemented on the 13.8 kV distribution system in the Charlottetown area. The area supplies approximately 8,000 customers, including a hospital, schools, and commercial and residential customers. The electrical system consists of both overhead sections and underground sections.

Grid modernization involves the installation of switching devices, voltage regulation devices, other distribution control devices, and communication networks to enable the automated monitoring and control of these devices. Action 10.4 of the Company's CCAS describes the benefits of distribution automation systems ("DAS") and the Company's intention to pursue a DAS pilot project for a selected area.

A comprehensive communication system consisting of a combination of fibre and cellular networks will be required to communicate to newly installed devices. The communication system will integrate into the existing operation technology network, meaning it will need to be cyber secure and meet all applicable protection, control, and supervisory control and data acquisition ("SCADA") system requirements. The newly installed devices will be able to be controlled and operated using this communication system.

Through this pilot, the initial investment required to implement and configure grid modernization technology will be made, meaning that in the future, expanding grid modernization into other areas of the Island electrical system will be more cost effective.

The Company is actively seeking government funding to offset some project costs. In May 2024, following a positive response to the Company's expression of interest submission, an application for project funding was submitted to the Federal Government. The application provided in Confidential Appendix Q-15, herein, is currently under review by the funding agency.

The ability to deliver this pilot project at reduced costs using government funding would reduce the financial impacts of implementing grid modernization technology. If approved, the funding will provide a contribution that would effectively halve the investment required to complete the project. If the funding application is not successful, the project should still proceed based on the potential for modernizations to the electrical system, but the scope would be reduced by approximately 50 per cent, meaning less automation would be deployed.

***Justification***

The project is justified based on the potential for grid modernization technology to increase grid visibility for ECC operators and to provide new opportunities for control. Increased grid visibility would also enable the Company to better utilize existing electrical system assets by providing measured power quality values, rather than relying on estimates, for making decisions to upgrade system components or add new assets such as feeders and substations. New control opportunities will enable the remote restoration of power to customers during outage events. This will increase the reliability, resiliency and flexibility of the power system when faced with unplanned outages and significant events such as hurricanes or extreme cold weather conditions.

Grid modernization technology could also help to facilitate the transition to more renewable sources of energy. PEI already has the highest per capita penetration of net metered distributed energy resources ("DER"), such as rooftop solar systems, in Atlantic Canada. Increased remote monitoring and control through grid modernization would enable more complex operation of voltage control equipment to support the continued growth of rooftop solar systems across the Island. Pending the results of the pilot, this could prevent or delay the need for more costly solutions that will otherwise be required to support further DER growth,[38] such as the addition of new feeders and substations.

[38] Maritime Electric is required to facilitate the adoption of net-metered DERs under PEI's *Renewable Energy Act*.

### *Costing Methodology*

A breakdown of the budget for the Charlottetown grid modernization pilot project is provided in Table 73. The funding amount for 2025 is budgeted under Contributions.

| TABLE 73<br>Breakdown of Multi-Year Budget<br>Charlottetown Grid Modernization Pilot | | | | | |
|---|---|---|---|---|---|
| **Description** | **2025 (A)** | **2026 (B)** | **2027 (C)** | **2028 (D)** | **Budget (E=A+B+C+D)** |
| Material | $ - | $ 900,000 | $ - | $ - | $ 900,000 |
| External Labour | 180,000 | 1,065,000 | 1,465,000 | 280,000 | 2,990,000 |
| Internal Labour and Transportation | 20,000 | 35,000 | 35,000 | 20,000 | 110,000 |
| **TOTAL** | **$ 200,000** | **$ 2,000,000** | **$ 1,500,000** | **$ 300,000** | **$ 4,000,000** |

Supporting information for the cost estimates in Table 73 is provided in Confidential Appendix Q-15.

To ensure this project is completed at lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for the project is January 2025 with a completion date in the fourth quarter of 2028.

### *Alternatives*

The only alternative is to defer the project; however, deferral would delay the opportunity to improve reliability, resiliency, and operational flexibility of the electrical system in the Charlottetown area. Deferral would also reduce the potential for government funding to reduce costs for customers, as it may not be available in the future.

**Future Commitments**

This is a multi-year project that will be completed over four years, from 2025 to 2028. If there are any changes to the evidence provided herein, including changes in scope, budget, funding contributions or timelines, subsequent to approval, further evidence will be provided in future capital budget applications.

**g. Power Transformers (Justifiable) $ 3,943,000**

Maritime Electric regularly reviews the age, condition, and loading of its power transformer fleet to determine if replacements, upgrades or additions are required. As power transformers are long-lead delivery items, they are budgeted over two years as multi-year projects.

In the 2024 Capital Budget Application, the Company identified a requirement to replace transformers at the Kensington and Albany substations, and to add one transformer to the Wellington substation. In this Application, two additional power transformers are budgeted. One will be installed at the Marshfield substation to increase the facility's transformation capacity, and the other will replace an end-of-life transformer at the Alberton substation. Additional information on each of these projects follows.

**i. Kensington Substation**

This will be the second year of the Kensington substation power transformer replacement project, that was fully described in the 2024 Capital Budget Application.

The project work plan for 2025 includes completion of factory acceptance testing, delivery to site, on-site testing, control cable wiring, and commissioning of the new transformer.

**ii. Albany Substation**

This will be the second year of the Albany substation power transformer replacement project, that was fully described in the 2024 Capital Budget Application.

The project work plan or 2025 includes completion of factory acceptance testing, delivery to site, on-site testing, control cable wiring, and commissioning of the new transformer.

**iii. Wellington Substation**

This will be the second year of the Wellington substation power transformer addition project, that was fully described in the 2024 Capital Budget Application.

The project work plan for 2025 includes completion of factory acceptance testing, delivery to site, on-site testing, control cable wiring, and commissioning of the new transformer. Provided the configuration of the Wellington substation, it will require the installation of an additional 69 kV switch and recloser on the transformers secondary.

**iv. Marshfield Substation**

The Marshfield substation currently has one 7.5/10 MVA power transformer that was new when the substation was completed in 2022. Electrical demand on the Marshfield substation has since increased by 18 per cent and it is anticipated the existing substation will be over its 10 MVA capacity limit in 2026. The Marshfield substation was built to accommodate a second power transformer to be added when required. As such, it can readily be upgraded with the addition of a 7.5/10 MVA power transformer, to increase its total capacity to 15/20 MVA. The configuration of the Marshfield substation also requires the installation of an additional 138 kV switch and recloser on the low voltage side of transformer.

**v. Alberton Substation**

The Alberton substation currently has a 4/5.3 MVA power transformer (1972 vintage) and a 7.5/10 MVA power transformer (1979 vintage). The 4/5.3 MVA must be replaced, as the dissolved gas analysis results indicate it has reached the end of its useful life. This transformer also contains a

PCB level greater than 2 ppm, which is an environmental concern in the event of a leak.

***Justification***

The planned power transformer projects are required based on the need to provide reliable service to customers and cannot be deferred.

***Costing Methodology***

A breakdown of the budget for power transformers is provided in Table 74.

**TABLE 74**
**Breakdown of Multi-Year Budget**
**Power Transformers**

| Description | 2024 (A) | 2025 (B) | 2026 (C) | Budget (D=A+B+C) |
|---|---|---|---|---|
| i. Kensington Substation | $ 720,721 | $ 746,683 | $ - | $ 1,467,404 |
| ii. Albany Substation | 720,721 | 746,683 | - | 1,467,404 |
| iii. Wellington Substation | 720,721 | 746,683 | - | 1,467,404 |
| iv. Marshfield Substation | - | 796,591 | 826,963 | 1,623,554 |
| v. Alberton Substation | - | 796,591 | 826,963 | 1,623,554 |
| External Labour (estimate) | - | 40,000 | 21,400 | 61,400 |
| Internal Labour and Transportation | 30,000 | 70,000 | 86,000 | 186,000 |
| **Subtotal** | **$ 2,192,163** | **$ 3,943,231** | **$ 1,761,326** | **$ 7,896,720** |
| **TOTAL (rounded)** | **$ 2,192,000** | **$ 3,943,000** | **$ 1,761,000** | **$ 7,896,000** |

To ensure the power transformer projects are completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement process. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

Supporting information for the cost estimates in Table 74 is provided in Confidential Appendix Q-15.

The expected completion of the three power transformer projects in their second year is end of December 2025. The Marshfield and Alberton substation transformer projects are expected to start in January 2025 and be completed by December 2026.

***Future Commitments***

Each power transformer replacement/addition is a multi-year project that will be completed over two years. If there are any changes to the evidence for the Marshfield and Alberton substation projects provided herein, including changes in scope, budget or timelines subsequent to approval, further evidence will be provided in the 2026 Capital Budget Application.

**h. <u>Substation Oil Containment Program</u> (Mandatory) $ 176,000**

The risk of power transformer oil being released into the environment is reduced considerably when an oil containment system is installed. This program involves the installation of oil containment systems in older substations and switching stations.

Maritime Electric currently has 29 power transformers which do not have oil containment systems. Depending on location, in some circumstances, one system can serve multiple transformers. For that reason, there are 20 transformer locations requiring an oil containment system.

The proposed budget is for the installation of oil containment at the Church Road substation. The same oil containment system that has been used at new substations and switching stations since 2015 will be installed, as it is the most cost-effective system in regard to installation and maintenance.

***Justification***

The substation oil containment system program is justified based on the need to protect against power transformer oil spills, which can result in environmental damage, costly cleanups and long-term contamination liabilities. For these reasons, the project cannot be deferred.

***Costing Methodology***

A breakdown of the budget for the substation oil containment program is shown in Table 75. A contingency has been budgeted as the vendor quotation is not specific to the substation that will be upgraded in 2025 and will need to be refreshed to allow for minor adjustments in price and scope of work that may be necessary to complete the project.

**TABLE 75**
**Breakdown of Proposed Budget**
**Substation Oil Containment Program**

| Description | Budget |
|---|---|
| Oil Containment System | $ 131,455 |
| Miscellaneous Civil Works | 25,000 |
| Internal Labour and Transportation | 11,000 |
| Contingency (5 per cent) | 8,373 |
| **Subtotal** | **$ 175,828** |
| **TOTAL (rounded)** | **$ 176,000** |

Supporting information for the cost estimates in Table 72 is provided in Confidential Appendix Q-15.

To ensure that this project is completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for the project is January 2025 with planned completion in the fourth quarter of 2025.

***Alternatives***

There is no alternative to transformer oil containment systems for protecting against oil leaks from transformer equipment at substations and switching stations.

### *Future Commitments*

This is not a multi-year capital budget commitment; however, it is a recurring capital requirement that is budgeted annually until all substations have oil containment systems in place.

### i. <u>Substation Modernization Program</u> (Justifiable) $ 560,000

The substation modernization program is necessary for the planned replacement and upgrading of deteriorated and substandard substation and switching station infrastructure, including the installation of backup generators, security cameras, mobile transformer bays, protective relaying, additional grounding, and fencing. Infrastructure replacement requirements are identified through inspections, professional engineering assessments and operating experience.

### *Justification*

The substation modernization program is justified based on the obligation to ensure the safety and reliability of the electrical system and the planned upgrades cannot be deferred.

### *Costing Methodology*

A breakdown of the budget for the substation modernization program is provided in Table 76.

**TABLE 76**
**Breakdown of Proposed Budget**
**Substation Modernization Program**

| Description | Budget |
|---|---|
| i. Backup Generator System | $ 103,000 |
| ii. Security Camera Installation | 108,000 |
| iii. Equipment Upgrades | 173,000 |
| iv. Mobile Transformer Accommodation | 116,000 |
| v. Fence Upgrades | 30,000 |
| vi. Internal Labour and Transportation | 30,000 |
| **TOTAL** | **$ 560,000** |

To ensure the substation modernization program is completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement process. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

A description of the items in Table 76 is provided below and a breakdown of the budget for each item is provided in Confidential Appendix Q-15.

**i. Backup Generator System**

In 2020, Maritime Electric began upgrading critical substations by replacing aged, or adding new, backup generators. Backup generators are important to a substation's reliability as they supply the required power to charge the substation batteries and keep systems online in the event of a power outage. The budget will enable the Company to install a backup generator at the Wellington substation as it does not yet have such equipment. Additional costs for transfer switches, disconnects and civil work are also included in the proposed budget.

**ii. Security Upgrades**

Security cameras are now a standard component of all new substations and switching stations. The addition of security cameras to existing locations is an additional measure to secure older stations and deter copper theft. The budget will enable the Company to install security cameras at the Airport substation, as it does not yet have such equipment.

**iii. Mobile Transformer Accommodation**

The Company has two 10 MVA mobile transformers, one with a high voltage rating of 69 kV and the other with a dual 138/69 kV high voltage rating. The mobile bays in older substations require expansion to be able to accommodate the larger dual voltage mobile transformer. The budget will allow the Company to upgrade the mobile transformer bay at the Dover substation, as it cannot accommodate the larger mobile transformer. This will involve civil works, modifications to the high voltage bus structures and the addition of a 69 kV switch.

**iv. Equipment Upgrades**

Substation equipment upgrades involve installing new reclosers with associated communication, in areas identified with automation potential or poor reliability, to allow for automated switching during outages. The budget will enable the Company to complete line recloser additions on adjacent distribution lines fed from different substations.

**v. Fence Upgrades**

The fence upgrades budget is for the replacement of fencing in the older substations and switching stations. The fencing is deteriorating and needs to be replaced as repairs are no longer sufficient. The proposed budget allocation will enable fence upgrades to be completed at substations, where required.

The expected start date for the substation modernization program is January 2025 with in-service dates throughout the year.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring capital requirement that is budgeted annually until all stations meet the current standards.

**j. 138 kV Breaker Replacement Program (Justifiable) $ 146,000**

The proposed budget is for the purchase of a 138 kV high voltage circuit breaker for the Y-111 transmission line termination in the Bedeque substation. The Company currently has 29 138 kV circuit breakers in service across the Island. While the electrical system can be postured to address a short duration circuit breaker outage for maintenance or replacement, it cannot survive an extended circuit breaker outage in the case of a circuit breaker failure. The current lead time for a replacement circuit breaker is approximately 52 weeks.

***Justification***

The 138 kV breaker replacement program is justified based on the need to replace equipment in the event of a failure. As circuit breakers are critical to system performance, this project is necessary and cannot be deferred.

***Costing Methodology***

A breakdown of the budget for the 138 kV breaker replacement program is shown in Table 77, and detailed support of the budget is provided in Confidential Appendix Q-15.

**TABLE 77**
**Breakdown of Proposed Budget**
**138 kV Breaker Replacement Program**

| Description | Budget |
|---|---|
| 138 kV Breaker | $ 113,713 |
| Control Cable and Miscellaneous Material (estimate) | 21,000 |
| Internal Labour and Transportation | 11,000 |
| **Subtotal** | **$ 145,713** |
| **TOTAL (rounded)** | **$ 146,000** |

To ensure that the 138 kV breaker replacement program is completed at the lowest possible cost, all material will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material requires sole sourcing, the Company will negotiate to achieve the best possible pricing.

***Alternatives***

There is no alternative to the replacement of this circuit breaker.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a regularly occurring capital requirement that is budgeted annually, as required.

**k. Communication Fibre – Church Road to Souris (Justifiable) $ 1,279,000**

The Company's current standard requires that, where feasible, all substations will be connected to the communication system using fibre optic cable. To meet this standard, the Souris substation will be connected to the communication system at the Church Road substation with fibre.

The proposed Church Road to Souris fibre communication project is an approximately 29 km fibre link from the Church Road substation to the Souris substation. This will benefit the Souris substation operations, as data from the Souris substation is currently transmitted via a 900-megahertz ("MHz") serial radio link which has limited bandwidth and reliability. A preliminary route is shown in Figure 11. Where possible, the fibre will also provide remote control from ECC to various devices on the distribution system. A communication link to distribution devices will improve safety and system reliability.

The Dingwells Mills substation is located between the Church Road substations and the Souris substation. As such, it can easily be connected to the fibre that will be installed through this project. This will benefit the Dingwells Mills substation operations, as data from the Dingwells Mills substation is also currently transmitted via a 900 MHz radio link.

**FIGURE 11**
**Church Road To Souris Preliminary Route**


### *Justification*

The proposed fibre project is justified on the need to provide reliable communication between the ECC, substations and field equipment. This communication is required to provide safe and reliable power. For the reasons provided, it cannot be deferred.

### *Costing Methodology*

A breakdown of the proposed budget allocation for installing fibre to the Souris substation from Church Road and Dingwells Mills substations, is shown in Table 78, and detailed support for the budget is provided in the Confidential Appendix Q-15.

| TABLE 78<br>Breakdown of Proposed Budget<br>Communication Fibre - Church Road to Souris | |
|---|---|
| **Description** | **Budget** |
| Fibre Optic Cable (estimate) | $ 147,000 |
| Labour for Fibre Installation | 220,000 |
| Material for Fibre Installation (estimate) | 90,000 |
| Wind Spoilers | 119,852 |
| Splicing Services (estimate) | 25,000 |
| Traffic Control (estimate) | 110,000 |
| Make-Ready Conversion (estimate) | 330,000 |
| Internal Labour and Transportation | 70,000 |
| Contingency (15 per cent) | 167,000 |
| **TOTAL (rounded)** | **$ 1,279,000** |

To ensure that the project is completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date for the project is May 2025, with completion expected by the end of the year.

***Future Commitments***

This is not a multi-year capital budget commitment.

**I. <u>Fibre Modifications Due to Road Alterations</u> (Recurring) $ 46,000**

Each year the Company relocates or replaces communication fibre to accommodate Provincial Government infrastructure projects such as sidewalk installations, sewer and water line extensions, road widening, road construction and bridge replacements.

***Justification***

The proposed provisional budget for fibre modifications due to road alterations is justified based on the obligation to provide safe and reliable service to customers and cannot be deferred.

***Costing Methodology***

A breakdown of the provisional budget for fibre modifications due to road alterations is shown in Table 79.

**TABLE 79**
**Historical and Proposed Capital Expenditures**
**Fibre Modifications Due to Road Alterations**

| Description | 2022 | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|
| Material and External Labour | $ 18,088 | $ 32,925 | $ 42,000 | $ 43,000 |
| Internal Labour and Transportation | 19,991 | 9,495 | 3,000 | 3,000 |
| **TOTAL** | **$ 38,079** | **$ 42,420** | **$ 45,000** | **$ 46,000** |

To ensure that all fibre modifications work is completed at the lowest possible cost, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

***Alternatives***

There are no alternatives when fibre modifications due to road alternatives are required, as the Company is obliged to accommodate Provincial Government work in public rights-of-way.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring provisional capital requirement that is budgeted annually.

## 6.2 Transmission Projects *$ 7,467,000*

The capital work proposed in the transmission projects category addresses the timely replacement of aged infrastructure, provides for upgrades due to system load growth, connects new facilities and equipment to the electrical system, improves reliability and power quality, reduces electrical losses and improves safety for workers by upgrading the system to meet current construction standards. The Company's asset database, field inspection results and reliability data serve as the primary tools for identifying necessary transmission system upgrade activities.

The proposed budget allocation for transmission projects provided in Table 80 was established based on historical expenditures and project cost estimates.

**TABLE 80**
**Historical and Proposed Capital Expenditures**
**Transmission Projects**

| Description | 2020[a] | 2021[b] | 2022[c] | 2023[d] | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 1,132,385 | $2,309,422 | $ 550,197 | $ 460,144 | $ 422,000 | $ 2,618,000 |
| Contractor Labour | 1,394,029 | 2,110,094 | 820,643 | 159,414 | 553,000 | 2,380,000 |
| Internal Labour and Transportation | 1,206,833 | 1,197,254 | 1,318,696 | 1,201,841 | 1,470,000 | 2,068,000 |
| Other | 71,590 | 27,468 | 57,990 | 312,228 | 104,000 | 401,000 |
| **TOTAL** | **$ 3,804,837** | **$ 5,644,238** | **$ 2,747,526** | **$ 2,133,627** | **$ 2,549,000** | **$ 7,467,000** |

a. Includes $1,010,047 for 2020 projects carried over and completed in 2021.
b. Includes $280,001 for 2021 projects carried over and completed in 2022.
c. Includes $198,478 for 2022 projects carried over and completed in 2023.
d. Includes $307,000 for 2023 projects carried over and to be completed in 2024.

### a. 69 kV and 138 kV Switch Program (Recurring) $ 1,186,000

The purpose of this program is to replace or upgrade and extend the life of selected 69 kV and 138 kV line switches to improve the reliability and safe operation of this equipment. The Company has an air switch inspection program and a transmission line refurbishment program that provides for annual inspection of switches and transmission lines. This year, the Company identified the requirement to replace two switches in the Alberton substation, two switches in the UPEI substation, and to stock spare 69 kV and 138 kV transmission switches and accessories to have them available for emergency backup replacement.[39] The switches will be motorized as the Company now has a number of motorized switches in operation and is in the process of converting manual air switches to motorized when replacement is necessary. Motorized air switches can be operated remotely and/or at the switch, to improve operational flexibility and worker safety.

Transmission switches have long lead times and having replacements available will allow for faster restoration times during emergencies, and prompt replacement of switches when annual inspection deficiencies are identified.

***Justification***

The proposed 69 kV and 138 kV switch program is justified on the obligation to maintain a safe and reliable electrical system and cannot be deferred.

***Costing Methodology***

A breakdown of the historical expenditures, 2024 budget and the proposed 2025 budget for the 69 kV and 138 kV switch program is shown in Table 81. The 2025 budget for materials is higher than the 2024 amount due to six switches being required, and to allow for the purchase of load breaking accessories that can be added to existing switches.[40] The budgeted amount for contractor labour has also been increased to allow for switch refurbishment activities by contractors that are qualified to perform work on an energized transmission system, which avoids the requirement for significant outages.

[39] In the 2024 Capital Budget, it was indicated that spare 69 kV and 138 kV transmission switches and accessories would be purchased. It was subsequently determined that two in-line switches on transmission line T-13 required replacement, so purchase of the spares had to be deferred.

[40] Load breaking accessories improve worker safety when opening switches on energized lines.

| TABLE 81<br>Historical and Proposed Capital Expenditures<br>69kV and 138 kV Switch Program | | | | | | |
|---|---|---|---|---|---|---|
| **Description** | **2020** | **2021[a]** | **2022[b]** | **2023** | **2024 Budget** | **2025 Budget** |
| Material | $ 288,649 | $ 215,375 | $ 155,034 | $ 195,410 | $ 171,000 | $ 464,000 |
| Contractor Labour | 18,794 | 14,127 | - | 20,143 | 5,000 | 253,000 |
| Internal Labour and Transportation | 259,036 | 343,942 | 432,322 | 429,543 | 455,000 | 469,000 |
| Other | - | 1,642 | 2,667 | 3,618 | - | - |
| **TOTAL** | **$ 566,479** | **$ 575,086** | **$ 590,023** | **$ 648,714** | **$ 631,000** | **$ 1,186,000** |

a. Includes $77,014 for 2021 projects carried over and completed in 2022.
b. Includes $96,000 for 2022 switch replacement projects carried over and completed in 2023.

The expected start date for work under the program is January 2025 and work will progress throughout the year.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring capital requirement that is budgeted annually.

**b. <u>Transmission Line Refurbishment</u> (Recurring) $ 1,031,000**

The 69 kV and 138 kV transmission lines are critical elements of Maritime Electric's electrical system.

The proposed budget provides for the inspection and resulting life extension activities of the transmission system, which will also support system reliability. Completion of ground inspection and correction of emergency and priority deficiencies found on the following 69 kV (T-line) and 138 kV (Y-line) transmission lines are planned for 2025:

- T-1 between West Royalty and Sherbrooke substations;
- T-2 between Charlottetown and Lorne Valley substations;
- T-10 between Lorne Valley and Dover substations;

- T-11 between Summerside and Sherbrooke substations;
- Y-112 between Church Road and Eastern Kings substations;
- T-13 between West Royalty and Charlottetown substations;
- T-15 between West Royalty and Charlottetown substations;
- Y-104 between West Royalty and West St. Peters substations;
- Y-108 between Church Road and Hermanville substations; and
- Y-115 between Sherbrooke and West Cape substations.

Photographs from recent ground inspections showing examples of deficiencies identified through the transmission line refurbishment program are provided in Appendix O.

***Justification***

The timely refurbishment of deteriorated transmission structures and equipment is justified on the obligation to maintain a safe and reliable electrical system and cannot be deferred.

***Costing Methodology***

A breakdown of the historical expenditures, 2024 budget and the proposed 2025 budget for transmission line refurbishment is shown in Table 82.

**TABLE 82**
**Historical and Proposed Capital Expenditures**
**Transmission Line Refurbishment**

| Description | 2020 | 2021 | 2022 | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 136,263 | $ 180,425 | $ 117,239 | $ 217,378 | $ 190,000 | $ 196,000 |
| Contractor Labour | 224,425 | 91,159 | 200,541 | 80,141 | 120,000 | 124,000 |
| Internal Labour and Transportation | 601,101 | 634,799 | 575,814 | 677,609 | 690,000 | 711,000 |
| Other | 8,272 | 598 | 38,434 | 1,610 | 27,000[a] | - |
| **TOTAL** | **$ 970,061** | **$ 906,981** | **$ 932,028** | **$ 976,738** | **$1,027,000** | **$ 1,031,000** |

a. Budget estimate for transmission aerial inspection.

The expected start date for the program is January 2025 and work will progress throughout the year.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring capital requirement that is budgeted annually.

**c. <u>Transmission Lines</u> (Justifiable) $ 4,737,000**

The proposed transmission lines budget provides for the timely replacement of aged infrastructure, connections to new or upgraded substations and equipment, improved reliability, reduced electrical losses and improved safety for workers by upgrading the system to meet current standards.

Three transmission line projects are planned for 2025, including:

i. Woodstock Switching Station Transmission Modifications;
ii. Y-106 Scotchfort to Lorne Valley; and
iii. Y-119 Extension to Scotchfort.

The Woodstock switching station transmission modifications project will connect transmission lines T-21 and Y-115 to the Woodstock switching station. As such, it is interdependent with the Woodstock switching station project, as described in Section 6.1a, herein. The combined budget of the two interdependent projects is shown in Table 83.

**TABLE 83**
**Combined Budget of Interdependent Projects**

| Description | 2023 (A) | 2024 (B) | 2025 (C) | Budget (D=A+B+C) |
|---|---|---|---|---|
| Woodstock Switching Station Transmission Modifications | $ - | $ - | $ 1,000,000 | $ 1,000,000 |
| Woodstock Switching Station | 1,741,000 | 7,669,000 | 5,161,000 | 14,571,000 |
| **TOTAL** | **$ 1,741,000** | **$ 7,669,000** | **$ 6,161,000** | **$ 15,571,000** |

The three-year Y-106 Scotchfort to Lorne Valley project will be in its second year in 2025. The project involves rebuilding and upgrading the existing 69 kV T-4 transmission line to 138 kV, and connecting Y-104 (via Y-106) to the Lorne Valley switching station. As such, it is interdependent with the Lorne Valley switching station expansion project as described in Section 6.1b, herein, and the Lorne Valley transmission modifications project, which will be included in the 2026 Capital Budget Application. The combined budget of the three interdependent projects is shown in Table 84.

**TABLE 84**
**Combined Budget of Interdependent Projects**

| Description | 2024 | 2025 | 2026 | Budget |
|---|---|---|---|---|
| Y-106 Scotchfort to Lorne Valley | $ 182,000 | $ 3,192,000 | $ 1,707,000 | $ 5,081,000 |
| Lorne Valley Switching Station Expansion | 98,000 | 2,221,000 | 4,820,000 | 7,139,000 |
| Lorne Valley Transmission Modifications | - | - | 640,000 | 640,000 |
| **TOTAL** | **$ 280,000** | **$ 5,413,000** | **$ 7,167,000** | **$ 12,860,000** |

The four-year Y-119 extension to Scotchfort project will be in its first year in 2025. The project will provide a third 138 kV transmission line from the Interconnection to central PEI. As such, it is interdependent with the Scotchfort substation project, as described in Section 6.1e, herein, a Y-109 Bedeque to Bannockburn Road rebuild project, and a Scotchfort substation transmission modifications project. The latter two projects will be included in the 2027 Capital Budget Application. The combined budget of the four interdependent projects is shown in Table 85.

**TABLE 85**
**Combined Budget of Interdependent Projects**

| Description | 2025 | 2026 | 2027 | 2028 | Budget |
|---|---|---|---|---|---|
| Y-119 Extension to Scotchfort | $ 545,000 | $ 4,032,000 | $ 4,071,000 | $ 4,240,000 | $12,888,000 |
| Scotchfort Substation | 872,000 | 9,405,000 | 5,917,000 | - | 16,194,000 |
| Y-109 Bedeque to Bannockburn Road | - | - | 5,045,000 | 5,226,000 | 10,271,000 |
| Scotchfort Substation Transmission Modifications | - | - | 421,000 | - | 421,000 |
| **TOTAL** | **$ 1,417,000** | **$13,437,000** | **$15,454,000** | **$ 9,466,000** | **$39,774,000** |

### Justification

The planned transmission line projects are justified on the obligation to provide safe and reliable service to customers. Additional details and justifications for these projects is provided in Appendix N.

### Costing Methodology

A breakdown of the historical expenditures, 2024 budget and the proposed 2025 budget allocation for transmission lines projects is shown in Table 86.

**TABLE 86**
**Historical and Proposed Capital Expenditures**
**Transmission Lines**

| Description | 2020[a] | 2021[b] | 2022[c] | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 707,473 | $ 1,913,622 | $ 330,763 | $ 47,356 | $ 61,000 | $ 1,958,000 |
| Contractor Labour | 1,150,810 | 2,004,806 | 620,103 | 59,130 | 118,000 | 1,684,000 |
| Internal Labour and Transportation | 347,696 | 198,504 | 257,721 | 94,688 | 265,000 | 813,000 |
| Other | 63,317 | 23,888 | 16,888 | 307,000[d] | 77,000[e] | 282,000[f] |
| **TOTAL** | **$ 2,269,296** | **$ 4,140,820** | **$ 1,225,475** | **$ 508,174** | **$ 521,000** | **$ 4,737,000** |

a. Includes $1,010,047 for 2020 projects carried over and completed in 2021.
b. Includes $202,986 for 2021 projects carried over and completed in 2022.
c. Includes $103,479 for 2022 projects carried over and completed in 2023.
d. Includes $307,000 for a 2023 project carried over and to be completed in 2024.
e. Classified as “Other” expense as it involves the purchase of an existing transmission asset from PEIEC.
f. Classified as “Other” expense as it involves consultant studies land purchase and permitting.

### Future Commitments

Woodstock transmission modifications is not a multi-year project. Y-106 Scotchfort to Lorne Valley is a multi-year project that will be completed over three years, from 2024 to 2026, and Y-119 extension to Scotchfort is a multi-year project that will be completed over four years, from 2025 to 2028. If there are any changes to the evidence for the Y-106 or Y-119 projects provided herein, including changes in scope, budget or timelines subsequent to approval, further evidence will be provided in future capital budget applications.

**d. <u>Transmission Corridor Widening</u> (Recurring) $ 381,000**

Under agreement with the Provincial Government, Maritime Electric is allowed to install its electrical lines at the outside edge of transportation rights-of-way. Accordingly, this also allows the Company to cut or trim vegetation in the right-of-way so that it does not contact lines; however, when the land directly adjacent to the right-of-way is treed, additional permissions are required, often from private landowners. In the past, private landowner permissions have been difficult to obtain and, therefore, many lines have significant tree stands directly next to them. Since Fiona, landowners are more aware of the risk that trees pose to power lines and there is a new opportunity to secure permissions that will allow the Company to reduce this risk by cutting trees and widening corridors.

Action 8.1 of the Company's CCAS describes new right-of-way widening initiatives which are being implemented in 2024. The transmission corridor widening program involves removing vegetation along existing transmission lines where it is outside the transportation right-of-way but in close proximity to lines. Under the program, transmission corridors selected for widening will be expanded by approximately 10 feet on one or both sides of the right-of-way, where feasible.

The vegetation removal under this program will be properly budgeted as a capital expenditure on the basis that the corridor widening (including danger tree removal) will be limited to areas that have not previously been cut.[41]

Maritime Electric's existing vegetation management program, which primarily targets trees within existing transportation right-of-way limits, will be used to deter new tree growth in the widened corridor once it is established.

***Justification***

This program to widen the transmission corridor and/or remove danger trees is justified based on the necessity to reduce tree contacts and damage to the

[41] Danger trees are further away from lines but still of concern due to their height.

transmission system during storms, and the obligation to provide safe and reliable service to customers.

Tree contacts are a leading cause of outages, particularly in storm events. During Dorian and Fiona, the transmission system experienced several outages due to trees, the majority of which were located adjacent to, but outside of, the transportation right-of-way. Tree contacts can cause damage to transmission poles and conductor, leading to longer duration outrages and higher restoration costs. Transmission corridor widening is an essential new program for Maritime Electric that will protect the transmission system from damage during future storm events. Similar to the tree removal that is required when a new transmission line is constructed, the tree removal that occurs as a result of corridor widening will be capitalized. Once a corridor is widened under this program, it will then be maintained (as an operational expense) under the vegetation management program.

***Costing Methodology***

A breakdown of the 2024 budget and the proposed 2025 budget allocation for transmission corridor widening is provided in Table 87.

**TABLE 87**
**Proposed Capital Expenditures**
**Transmission Corridor Widening**

| Description | 2024 Budget | 2025 Budget |
|---|---|---|
| Contractor Labour | $ 310,000 | $ 319,000 |
| Internal Labour and Transportation | 60,000 | 62,000 |
| **TOTAL** | **$ 370,000** | **$ 381,000** |

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is proposed as a recurring capital requirement that will be budgeted annually.

**e. Satellite-Based Vegetation Imaging – Transmission**

**(Recurring) $ 132,000**

Action 8.3 of the Company's CCAS describes a pilot-project evaluation of satellite technology for vegetation management planning. The evaluation found the technology to be effective for providing accurate, real-time data on vegetation location and density along transmission lines.

The satellite-based vegetation imaging program involves evaluating vegetation condition, density, growth-type, and proximity to transmission infrastructure, as well as performing risk-based analysis and prioritization of vegetation management activities. As the technology is applicable to both transmission and distribution lines, the material and labour costs of the program have been divided between the Transmission and Distribution capital budget categories.[42]

Satellite-based technology uses high-resolution, multispectral, and synthetic aperture radar data from satellite constellations, and can also incorporate aerial imagery from drones, helicopters, fixed-wing planes, and light detection and ranging data. In conjunction with the Company's GIS, this technology uses the data to inform proprietary models that analyze vegetation condition, growth, and risk factors. The technology can also measure and estimate annual growth patterns to forecast future-year requirements for vegetation management, and to help identify where future satellite scans should be focused.

***Justification***

Establishing a recurring vegetation management risk analysis and prioritization program using satellite imagery is justified based on the necessity to reduce tree contacts and related damage to the transmission system, and the obligation to provide safe and reliable service to customers. Satellite technology can effectively provide real-time data on vegetation location and density that is more accurate and efficient to collect, than comparative ground inspection data.

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[42] 25 per cent of the program costs have been allocated to Transmission, and 75 per cent of the costs have been allocated to Distribution (see Section 5.5e, herein).

Tree contacts are the leading cause of outages to customers, both during non-storm and storm events. Furthermore, tree contacts can cause damage to transmission poles and conductor, leading to longer duration outages and higher restoration costs. This risk and prioritization-based program will inform the Company's vegetation management program and the transmission corridor widening program, including the identification and removal of danger trees.[43] Targeted areas will be systematically prioritized as the highest risk, based on condition, criticality, and customer and/or transmission system impact. This program will also ensure that both operating and capital expenditures for vegetation management are targeted in the areas that provide the most transmission system reliability benefit to customers.

***Costing Methodology***

A breakdown of the proposed budget for collection and analyses of transmission system satellite-based vegetation imaging is provided in Table 88.

**TABLE 88**
**Proposed Capital Expenditures**
**Satellite-Based Vegetation Imaging – Transmission**

| Description | 2025 Budget |
|---|---|
| Software, Data and Vendor Labour | $ 119,000 |
| Internal Labour and Transportation | 13,000 |
| **TOTAL** | **$ 132,000** |

Supporting information for the satellite-based vegetation imaging program is provided in Confidential Appendix Q-16.

[43] Vegetation management activity that occurs in existing transmission and distribution corridors is generally recorded as an operating expense. Vegetation management activity that occurs for the first time in new or expanded corridors is generally recorded as a capital expense, with all subsequent vegetation management activity recorded as an operating expense.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is proposed as a recurring capital requirement that will be budgeted annually.

For the first year of the program, software implementation and configuration costs will be capitalized along with satellite imagery and risk analysis costs for the entire transmission system to establish a baseline. Each subsequent year, approximately 20 per cent of the transmission system will be analyzed for vegetation management work prioritization. As such, the capital and operating costs of the program in future years will be reduced accordingly.[44]

[44] Annually recurring vendor products and services after the first year of the transmission system program are expected to cost approximately $27,000 (2024 estimate) for new satellite imagery and risk analysis (a capital expense) and $3,000 (2024 estimate) for software maintenance and support (an operating expense). Future annual costs will vary with Canada-US currency exchange rates, inflation, and supplier pricing.

**7.0 CORPORATE** ***$ 3,003,000***

**7.1 Corporate Services** ***$ 872,000***

**a. Recurring Annual Capital Requirements (Work Support Services) $ 667,000**

As Company facilities age and deteriorate, annual upgrades and replacements of various components are required. Also, experience indicates that unplanned and emergency events will occur that require capital replacements and refurbishments. Performing upgrades and refurbishments to ensure facilities remain in adequate condition prior to complete failure is required to ensure the health and safety of employees, customers and contractors, provide a functional work environment, and to avoid costly emergency repairs or replacements.

Capital expenditures on facilities historically have been required to cover items including:

- Window and doors;
- Security systems and fencing;
- Roofing and siding;
- Paving for facility access and parking;
- Office furniture and equipment; and
- Unforeseen capital expenditures.

As the projects under this budget category are unplanned and identified on an as required basis, cost projections at the item level cannot be determined in advance and, therefore, the proposed budget allocation is provisional.

**Justification**

This proposed provisional budget allocation is justified on the obligation to provide safe and functional facilities for employees, contractors and the public. For this reason, when projects arise throughout the year, they cannot be deferred.

### Costing Methodology

A breakdown of the historical expenditures, 2024 budget and the proposed 2025 budget for recurring annual capital requirements is shown in Table 89.[45] [46]

**TABLE 89**
**Historical and Proposed Capital Expenditures**
**Recurring Annual Capital Requirements**

| Description | 2020 | 2021 | 2022[b] | 2023[c] | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material[a] | $ 190,698 | $ 342,063 | $ 503,986 | $ 558,955 | $ 458,000 | $528,000[d] |
| External Labour | 13,963 | 24,004 | 44,895 | 441,000 | - | 123,000 |
| Internal Labour and Transportation | 34,596 | 14,339 | 13,947 | 44,170 | 15,000 | 16,000 |
| Other | 76,158 | 119,664 | 65,504 | 114,832 | - | - |
| **TOTAL** | **$ 315,415** | **$ 500,070** | **$ 628,332** | **$1,158,957** | **$ 473,000** | **$ 667,000** |

a. Material includes external labour for supply and install contracts.
b. Includes $225,000 for 2022 projects carried over and completed in 2023.
c. Includes $30,000 budgeted for 2023 projects carried over and to be completed in 2024.
d. Includes the five-year average amount for “Other” expenditures.

To ensure projects are completed at the lowest possible costs, all material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

### Future Commitments

This is not a multi-year capital budget commitment; however, it is a recurring provisional capital requirement that is budgeted annually.

[45] The 2025 budget amount in Table 89 is based on a five-year average of actual and budgeted expenditures, from 2020 to 2024, that were normalized to 2025 dollars using an annual escalation rate of 3 per cent.
[46] For the 2025 Budget, the sum total of “External Labour” and “Internal Labour and Transportation” equals the five-year average for labour, not the individual amounts for each item.

**b. *Comprehensive Building Condition Assessment***
**(Work Support Services) $ 205,000**

Maritime Electric's main office building, located at 180 Kent Street, requires a comprehensive building condition assessment to determine how the Company should proceed to address issues of concern specific with this aged asset.

Originally constructed in 1974, the 180 Kent Street building was purchased by Maritime Electric in 1989 and was completely refurbished at that time, with the exception of a section of the second floor, in order for the building to meet the needs of the Company and its staff. Since that time, there have been no major renovations to the building; however, the elevators were refurbished in 2019 and 2020, and the roof was replaced in 2022. Both of these projects were required due to age and deterioration, and approved through prior capital budget applications.

The comprehensive building assessment will be used to determine whether it would be more cost effective to either: (i) renovate and upgrade; or (ii) construct or purchase a new main office building and sell the existing asset.

The assessment will consider the exterior repair and upgrades, and the interior renovations that will be required to accommodate the anticipated needs of the Company in the short, medium and long term.

***Building Exterior***

The assessment of the building exterior will focus on the building envelope and the exterior equipment and facilities associated with the buildings' mechanical and electrical systems. The building envelope assessment will involve detailed inspection of siding, soffits, flashings, windows, air louvers, insulation and entry/egress areas. Infrared thermographic inspection will also be completed to assess the thermal efficiency of the building. Exterior components of mechanical and electrical systems include HVAC equipment, water and wastewater connections and the electrical service entrance.

***Building Interior***

The assessment of the building interior will include the mechanical systems for HVAC, fire protection, and water/wastewater plumbing and fixtures, and the facilities and equipment for electrical supply, lighting, communications and emergency power backup. The assessment will also involve a review of present and future office and meeting space requirements, considering recently reclaimed floor space as a result of terminating leases with external tenants, and staffing requirements, with electrification, renewable energy transition, and customer growth expected to continue.

**Justification**

The project is justified on the obligation to provide safe, functional and sustainable facilities. Based on the age and condition of the 180 Kent Street building, and its limited workspaces, the Company expects a significant amount of investment will be required to renovate and upgrade the building to meet its current and future needs. The requested assessment will provide an accurate estimate of the required investment. Alternatively, given the age and condition of the existing building, constructing a new building to meet the Company's needs may be a cheaper option. The assessment will also provide an evaluation of the market value of 180 Kent Street and provide an estimated cost to construct a new building, potentially on the CGS site. Without this assessment, the Company will not be able to put forward the least cost option for the Commission's approval. For the reasons provided, the project cannot be deferred.

**Costing Methodology**

The proposed budget allocation is an estimate of the cost to engage an engineering or architecture consulting firm with expertise in building assessment to carry out the study.

**Alternatives**

There is no alternative to completing the project as planned, as the Company does not currently have adequate information to determine if it should renovate and upgrade the 180 Kent Street building, or construct/purchase a new main office building and sell the existing asset. Also, as this project was previously deferred during the 2023 Capital Budget Application review process, further deferral should not occur.

**Future Commitments**

This is not a multi-year capital budget commitment; however, the resulting assessment will be used to determine future capital investment with respect to the 180 Kent Street building, and potential cost-effective alternatives.

## 7.2 Information Technology (Work Support Services) *$ 2,131,000*

### a. Hardware Acquisitions (Work Support Services) $ 832,000

The proposed budget allocation for information technology ("IT") network hardware acquisitions provides for the purchase and configuration of computer hardware additions, and life-cycle replacement or upgrading of existing hardware, including personal computers (e.g., desktops, laptops and tablets), printers, servers and communication equipment (e.g., switches and routers in the data centre). This equipment is critical to ensuring the efficient operation of the Company's business IT network and provision of service to customers. The Company has approximately 360 personal computers and printers in use, which are typically replaced on a five-to-seven-year cycle. The replacement or upgrade of servers and communications equipment is determined based on the existing performance of the equipment, the ability to expand the equipment for future growth, the criticality of the equipment based on the business or customer impact should the equipment fail, and the cost of replacing or upgrading as compared to the operating costs of the existing equipment. Industry practice is to replace servers and communication equipment every five years.

In 2019, the IT Department became responsible for cybersecurity of the operational technology ("OT") network. Foundational work beginning in 2020 and ending in 2024 involved the replacement of dated communication equipment in 40 sites. The life cycle of this equipment is five years. In 2025, vendor support for equipment in several substations will expire and no longer be warranty eligible or received critical security patch updates. The budget for hardware acquisitions includes $424,000 for replacing this equipment.

***Justification***

Hardware acquisitions are justified based on the need to maintain reliable IT and OT networks, which is critical to the overall service the Company provides to customers.

***Costing Methodology***

A breakdown of the historical expenditures, 2024 budget and proposed 2025 budget for hardware acquisitions is shown in Table 90

**TABLE 90**
**Historical and Proposed Capital Expenditures**
**Hardware Acquisitions**

| Description | 2020 | 2021[a] | 2022[b] | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Material | $ 227,580 | $ 244,457 | $ 780,316 | $ 194,509 | $ 483,000 | $ 698,000 |
| Internal Labour and Transportation | 7,114 | 26,668 | 178,793 | 142,485 | 90,000 | 134,000 |
| **TOTAL (rounded)** | **$ 234,694** | **$ 271,125** | **$ 959,109** | **$ 336,994** | **$ 573,000** | **$ 832,000** |

a. Includes $95,534 for 2021 projects carried over and completed in 2022.
b. Includes the replacement of the storage area network and server farms, which is not an annual occurrence.

The proposed budget for hardware acquisitions by equipment type is shown in Table 91. The budget is based on the most recent purchases and vendor quotes for similar equipment and the estimated cost of internal labour required to deploy the equipment.

| TABLE 91<br>Hardware Acquisitions | |
|---|---|
| **Description** | **Budget** |
| Personal Computing Devices and Printers | $ 138,000 |
| Servers and Communication Equipment | 560,000 |
| Internal Labour and Transportation | 134,000 |
| **TOTAL** | **$ 832,000** |

Supporting information for the hardware acquisitions budget is provided in Confidential Appendix Q-17.

To ensure this project is completed at the lowest possible cost, all hardware acquisitions will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of supply require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date of this project is January 2025 with in-service dates throughout the year.

***Alternatives***

The only alternative is to defer hardware acquisitions. This is not recommended as computer hardware, servers and communication equipment are critical to business and electrical system operations, including providing service to customers.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring capital requirement that is budgeted annually.

**b. <u>Purchased Software and Upgrades</u> (Work Support Services) $ 367,000**

Maritime Electric's IT network relies on a wide variety of software to deliver service to customers. Vendors that supply and support this software charge for the ongoing development of new features, the creation of security patches and the support of system customizations. These enhancements improve the functionality, security and service life of the software. The internal labour component of the proposed budget allocation provides for software installation, patching, upgrading and testing.

Microsoft supplies end-user business software such as word processing, spreadsheets and email as well as key data centre software including the corporate database management system and the financial management suite. Microsoft also supplies most core operating systems on Company servers and computers. The budget amount provides for access to the latest versions of each software product.

In recent years, Maritime Electric has moved more and more of its IT applications to the Software as a Service ("SaaS") model. Instead of purchasing software and installing it on its own hardware, the Company often purchases the software as a subscription. As such, the vendor hosts the application from its data center or that of a third party. The SaaS model eliminates the labour-intensive upgrade and patching process, as well as reduces the hardware required to host the software. This trend has been occurring in many industries now for several years, to the extent that many vendors are now only offering SaaS products.

Maritime Electric follows Chartered Professional Accountants Canada Handbook, Accounting Standards for Private Enterprises Part II - ASPE. With the change to the SaaS model, new accounting guidance for "customer's accounting for cloud computing arrangements" was issued in ASPE Accounting Guideline 20 ("AcG-20"). As a result, all intangible elements associated with a software service are now being expensed as incurred, as they are no longer tangible. AcG-20 is effective for fiscal periods beginning on or after January 1, 2024.

As a result of this change, the budget for purchased software and upgrades in 2025 has been reduced relative to prior years.

ESRI is the Company's provider of enterprise GIS solutions. ESRI maps are embedded in most Maritime Electric applications including the customer information system, vegetation management system and the outage restoration map on the Company's website. The budget amount also provides for the continued support by the vendor, which contributes to the effective operation of the GIS.

Cybersecurity software is sourced from specialized vendors and provides essential services to Maritime Electric in order to maintain a safe network. These solutions include the management of mobile devices, second factor authentication and intrusion detection.

The Company also uses a wide variety of smaller applications that support software development, engineering design, billing, and other business functions.

***Justification***

Purchased software and upgrades are justified based on the need to have functional software applications and continued vendor support for the products being utilized. This is critical to the overall service the Company provides to customers and helps to ensure the security and operation of the IT network.

***Costing Methodology***

A breakdown of the historical expenditures, 2024 budget, and proposed 2025 budget allocation for purchased software and upgrades is shown in Table 92.

| TABLE 92<br>Historical and Proposed Capital Expenditures<br>Purchased Software and Upgrades | | | | | | |
|---|---|---|---|---|---|---|
| **Description** | **2020** | **2021** | **2022** | **2023** | **2024 Budget** | **2025 Budget** |
| Material | $ 383,780 | $ 434,326 | $ 511,829 | $ 548,415 | $ 762,000 | $ 295,000 |
| Internal Labour and Transportation | 60,365 | 41,430 | 34,902 | 59,671 | 120,000 | 72,000 |
| **TOTAL** | **$ 444,145** | **$ 475,756** | **$ 546,731** | **$ 608,086** | **$ 882,000** | **$ 367,000** |

The proposed budget for purchased software and upgrades by software type is shown in Table 93. The budget is based on recent purchases and vendor quotes, as well as the estimated cost of internal labour required to install the software.

| TABLE 93<br>Breakdown of Proposed Budget by Software Type<br>Purchased Software and Upgrades | |
|---|---|
| **Description** | **Budget** |
| Great Plains Financials | $ 22,000 |
| ESRI Mapping | 65,000 |
| Software Development Tools | 18,000 |
| Cybersecurity Software | 62,000 |
| Miscellaneous Software Upgrades | 109,000 |
| New Purchases | 19,000 |
| Internal Labour and Transportation | 72,000 |
| **TOTAL** | **$ 367,000** |

Supporting information for the purchased software and upgrades budget is provided in Confidential Appendix Q-17.

To ensure this project is completed at the lowest possible cost, all purchased software and upgrades will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of supply require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The expected start date of this project is January 2025 with in-service dates throughout the year.

***Alternatives***

The only alternative is to defer purchased software and upgrades projects. This is not recommended as software functionality and security is critical to business operations, including providing service to customers.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring capital requirement that is budgeted annually.

**c. Cybersecurity Enhancements (Work Support Services) $ 643,000**

Cybersecurity is a core strategic focus for Maritime Electric. Cyber threats are increasingly more complex, frequently utilizing highly sophisticated forms of malware to mount persistent and targeted attacks. The consequences of dealing with security breaches are significant and can include privacy violations, data corruption, loss of asset and system control, loss of customer confidence, financial penalties, legal exposure and negative press. This issue is even more concerning for companies with critical infrastructure assets such as Maritime Electric. For these reasons, the Company continues to invest in cybersecurity initiatives. Areas of investment are driven by the cyber risk management program ("CRMP"). The CRMP evaluates core cyber risks against existing controls and identifies projects that can eliminate or mitigate risk. These projects drive a rolling five-year cybersecurity roadmap that guides investment. This proposed budget allocation will progress the roadmap in several areas.

The proposed cybersecurity enhancements work will involve review and analyses of the IT network and the OT network by an external security specialist. The review evaluates the many facets of security against the latest trends in criminal cyber activity. The process consists of an independent audit, recommendations assessment, and the development and implementation of a work plan. The funds required to carry out the workplan are also included in the proposed budget.

Upgrades on the IT network will focus on the refresh of the Network Access Control solution. The existing hardware has been in place for five years and is due for replacement. A review will be conducted to choose between renewing/replacing the existing solution or replacing with an alternate vendor's solution.

With the completion of the substation communication refresh project in 2024, the cyber team can now take advantage of substation asset management and monitoring software, currently installed in four substations. The budget will expand the coverage of this software across an additional ten substations.

***Justification***

The project is justified on the basis that cyber threats are constantly evolving and the protection of the IT and OT networks is critical to the security of the Company's asset and customer data.

***Costing Methodology***

A breakdown of the historical expenditures, 2024 budget and the proposed 2025 budget allocation for cybersecurity enhancements is shown in Table 94.

| TABLE 94<br>Historical and Proposed Capital Expenditures[a]<br>Cybersecurity Enhancements | | | | | | |
|---|---|---|---|---|---|---|
| **Description** | **2020[b]** | **2021[c]** | **2022[d]** | **2023[e]** | **2024 Budget** | **2025 Budget** |
| Material | $ 61,965 | $ 445,433 | $ 247,517 | $ 390,883 | $ 627,000 | $ 473,000 |
| External Labour | 50,785 | - | - | - | - | - |
| Internal Labour and Transportation | 129,747 | 210,409 | 259,675 | 123,967 | 160,000 | 170,000 |
| **TOTAL** | **$ 242,497** | **$ 655,842** | **$ 507,192** | **$ 514,850** | **$ 787,000** | **$ 643,000** |

a. All cybersecurity initiatives in 2022, 2023 and 2024 have been consolidated under budget item 7.2c Cybersecurity Enhancements. Historical expenditures data represents the total amount for the equivalent cybersecurity initiatives in that year.
b. In 2020, the equivalent cybersecurity initiatives were Capital Budget items 7.2d Business Network Security Review and 7.2e Cybersecurity Enhancements.
c. In 2021, the equivalent cybersecurity initiatives were Capital Budget items 7.2d Business Network Security Review, 7.2e Cybersecurity Enhancements and 7.2f Operations Network Data Centre Infrastructure.
d. Includes $71,285 for 2022 cybersecurity enhancements carried over and completed in 2023.
e. Includes $57,000 budgeted for 2023 cybersecurity enhancements carried over and to be completed in 2024.

A breakdown of the cybersecurity enhancements budget is shown in Table 95. The budget is based on recent purchases and vendor quotes as well as the estimated cost of internal labour required to complete the projects.

| TABLE 95<br>Breakdown of Proposed Budget<br>Cybersecurity Enhancements | |
|---|---|
| **Description** | **Budget** |
| IT Network | $ 51,000 |
| OT Network | 422,000 |
| Internal Labour and Transportation | 170,000 |
| **TOTAL** | **$ 643,000** |

Supporting information for the cybersecurity enhancements budget is provided in Confidential Appendix Q-17.

To ensure this project is completed at the lowest possible cost, material and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

The project will start in January 2025 with in-service dates throughout the year.

***Alternatives***

The only alternative is to defer the proposed cybersecurity enhancements. This is not recommended as the protection of the Company's IT and OT networks is increasingly important, with cyber-attacks occurring more frequently and becoming more sophisticated.

***Future Commitments***

This is not a multi-year capital budget commitment; however, it is a recurring capital requirement that is budgeted annually.

**d. Intranet Refresh (Work Support Services) $ 116,000**

The Maritime Electric intranet was developed by internal IT staff in 1998. The existing intranet provides employees access to critical information including corporate software, policies and procedures, training materials, announcements, and reporting menus. The technology used to create the intranet is obsolete and limits collaboration with many new software tools. The project will also provide an opportunity to reorganize content, remove dated links and improve communication across the Company.

***Justification***

This project is justified based on the deterioration of the existing intranet and how cumbersome it has become to use. An updated interface to key tools for employees will improve efficiency and communication.

***Costing Methodology***

A breakdown of the proposed budget for the intranet refresh project is shown in Table 96.

| TABLE 96<br>Breakdown of Proposed Budget<br>Intranet Refresh | |
|---|---|
| **Description** | **Budget** |
| Software and Vendor Labour (estimate) | $ 66,000 |
| Internal Labour and Transportation | 50,000 |
| **TOTAL** | **$ 116,000** |

Supporting information for the project budget is provided in Confidential Appendix Q-17.

To ensure this project is completed at the lowest possible cost, software and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

***Alternatives***

The only alternative is to defer the project; however, this is not recommended as existing system is now obsolete and increasingly cumbersome to navigate and maintain.

***Future Commitments***

This is not a multi-year capital budget commitment.

**e. <u>Great Plains Interface Upgrade</u> (Work Support Services) $ 81,000**

Maritime Electric uses Great Plains ("GP") software for recording, tracking and reporting the Company's financial transactions. GP is a fully integrated suite of products that include General Ledger, Accounts Payable, Accounts Receivable, Purchasing and Financial Reporting. The GP system relies on electronic interfaces to several sources. These sources include credit card vendors, fleet data and the Company's billing system. These inputs are processed by an internally developed system that was built in 2003. This budget amount will allow the system to be rewritten and enhanced in a newer technology that will continue to support the financial system for years to come.

***Justification***

The project is justified based on the criticality of the Great Plains system to the Company and to ensure its interfaces continue to be supported.

***Costing Methodology***

A breakdown of the proposed budget for upgrading Great Plains for software is provided in Table 97.

**TABLE 97**
**Breakdown of Proposed Budget**
**Great Plains Interface Upgrade**

| Description | Budget |
|---|---|
| Vendor Labour | $ 31,000 |
| Internal Labour and Transportation | 50,000 |
| **TOTAL** | **$ 81,000** |

Supporting information for the project budget is provided in Confidential Appendix Q-17.

***Alternatives***

The only alternative is to defer the project; however, this is not recommended as the existing software is aged and is due to be upgraded.

***Future Commitments***

This is not a multi-year capital budget commitment.

**f. ECC Load Forecasting Tool $ 92,000**

This project involves purchasing and integrating load forecasting software into ECC operations for improved scheduling of energy requirements from NB Power.

Renewable energy sources such as solar and wind are inherently variable and dependent on weather conditions. As the penetration of these energy sources on to the grid increases, Maritime Electric's ECC operators face challenges scheduling renewable energy production, which is done each hour. Any error in scheduling can lead to costly imbalance charges from the balancing authority, the New Brunswick System Operator, and the possibility of having to operate on-Island diesel generation during hold to schedule events.[47] Load forecasting tools, combined with weather forecasting data, enable better integration of these renewables sources onto the grid. By predicting fluctuations in renewable generation and adjusting load schedules accordingly, Maritime Electric can maximize the use of clean energy and reduce the reliance on fossil fuels, while lowering imbalance charges. Hold to schedule events can also lead to supply shortages, if there is not enough dispatchable on-Island generation available to operate and supply the load, when they occur.

***Justification***

The project is justified based on the operational requirement to accurately forecast load and schedule energy on an hourly basis. Inaccurate forecasting can result in costly imbalance charges, unnecessary operation of on-Island diesel generators, and energy shortfalls when loads are high.

***Costing Methodology***

A breakdown of the proposed budget for the ECC load forecasting tool is provided in Table 98.

[47] Hold to schedule events limit the amount of energy that can be transferred to PEI through the Interconnection. They can occur when on-Island renewable energy production is less than forecast and can result in on-Island dispatchable generation having to operate, if required due to load.

| TABLE 98<br>Breakdown of Proposed Budget<br>ECC Load Forecasting Tool | |
|---|---|
| **Description** | **Budget** |
| Software and Vendor Labour | $ 37,000 |
| External Labour (estimate) | 20,000 |
| Internal Labour and Transportation | 35,000 |
| **TOTAL** | **$ 92,000** |

Supporting information for the project budget is provided in Confidential Appendix Q-17.

To ensure this project is completed at the lowest possible cost, software and external labour will be obtained through competitive procurement processes. In situations where time constraints, or limited availability of material and/or service providers require sole sourcing, the Company will negotiate to achieve the best possible pricing.

***Alternatives***

The only alternative is to defer the project; however, this is not recommended given the possible cost, environmental and security of supply implications of inaccurate load and energy supply requirement forecasting.

***Future Commitments***

This is not a multi-year capital budget commitment.

## 8.0 CAPITALIZED GENERAL EXPENSE *$ 919,000*

The Capitalized General Expense ("GEC") budget amount includes a portion of administrative costs (predominately labour) that are properly recognized as part of the Company's overall capital expenditure program. These recurring expenditures represent an allocation of administrative costs, not specific to any one capital project, but rather as part of the overall development, implementation and management of the Company's capital budget program. The costs are labour and transportation related and derived from departments that support the overall capital program of the Company, primarily Finance and Purchasing, Corporate and Capital Planning and Stores operations.

The proposed budget reflects historical spending over the past five years as shown in Table 99.

**TABLE 99**
**Capitalized General Expenses**

| Description | 2020 | 2021 | 2022 | 2023 | 2024 Budget | 2025 Budget |
|---|---|---|---|---|---|---|
| Stores | $ 412,884 | $ 434,102 | $ 435,829 | $ 461,000 | $ 566,000 | $ 633,000 |
| Finance and Purchasing | 76,861 | 78,925 | 86,090 | 82,000 | 85,000 | 87,000 |
| Corporate and Capital Planning | - | 168,106 | 174,698 | 187,000 | 193,000 | 199,000 |
| **TOTAL** | **$ 489,745** | **$ 681,133** | **$ 696,617** | **$ 730,000** | **$ 844,000** | **$ 919,000** |

## 9.0 INTEREST DURING CONSTRUCTION $ 869,000

The Interest During Construction ("IDC") budget amount represents an allowance for the cost of funds used during the construction of certain assets. It is reflected in the accounts as an offset to financing costs and is based on the Company's cost of borrowing. This amount is allocated to fixed assets and recovered through amortization over the life of the assets. Appendix P to this Application provides the calculation of the 2025 budget provision for IDC.

# 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 3.6 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 2025 Annual Capital Budget and for certain approvals incidental to such an order.

UPON receiving an Application by Maritime Electric Company, Limited (the "Company") for approval of the Company's capital budget for year 2025;

AND UPON considering the Application and Evidence filed in support thereof;

NOW THEREFORE, for the reasons given in the annexed Reasons for Order and pursuant to the *Electric Power Act*;

IT IS ORDERED THAT
The 2025 Capital Budget Application of the Company, filed herein on August 2, 2024 and summarized below is approved:

| 2025 Capital Budget Application Summary | |
|---|---|
| Generation | $ 1,137,000 |
| Distribution | 43,772,000 |
| Transmission | 27,032,000 |
| Corporate | 3,003,000 |
| Capitalized General Expense | 919,000 |
| Interest During Construction | 869,000 |
| **TOTAL** | $ 76,737,000 |
| Less: Contributions | (1,550,000) |
| **TOTAL (Net)** | **$ 75,182,000** |

DATED at Charlottetown, Prince Edward Island, this ___ day of _____, 2024.

BY THE COMMISSION:

________________________________________

Chair

________________________________________

Commissioner

________________________________________

Commissioner

# APPENDIX A

## Summary of Actual and Proposed Capital Expenditures
## (2016 to 2029)

| Maritime Electric Company, Limited<br>Summary of Actual and Proposed Capital Expenditures (2016 to 2029) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
| | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Budget | Budget | Forecast | Forecast | Forecast | Forecast |
| Generation (A) | 1,241,112 | 1,064,720 | 1,000,667 | 485,340 | 966,480 | 1,107,404 | 1,140,364 | 744,940 | 1,430,000 | 1,137,000 | 2,749,000 | 2,196,000 | 3,507,000 | 2,377,000 |
| Distribution (B) | 18,246,306 | 19,834,463 | 21,445,487 | 23,777,736 | 23,509,596 | 29,159,593 | 25,693,272 | 35,686,236[1] | 57,548,000[3] | 60,407,000[7] | 51,648,000 | 51,382,000 | 53,997,000 | 56,028,000 |
| Transmission (C) | 8,283,251 | 10,832,373 | 6,989,530 | 8,674,018 | 10,299,290 | 11,830,346 | 9,488,482 | 12,268,511 | 17,513,000 | 27,032,000 | 37,610,000 | 40,376,000 | 38,122,000 | 38,329,000 |
| Corporate (D) | 1,039,510 | 841,786 | 2,143,044 | 1,850,589 | 1,687,498 | 2,406,915 | 3,061,980 | 3,758,075[2] | 12,083,000[4] | 10,498,000[8] | 10,793,000 | 6,958,000 | 4,947,000 | 4,341,000 |
| Subtotal (E=A+B+C+D) | 28,810,179 | 32,573,342 | 31,578,728 | 34,787,683 | 36,462,864 | 44,504,258 | 39,384,098 | 52,457,762 | 88,574,000 | 99,074,000 | 102,800,000 | 100,912,000 | 100,573,000 | 101,075,000 |
| GEC (F) | 477,714 | 502,450 | 475,368 | 567,505 | 489,745 | 681,043 | 696,617 | 841,522 | 844,000 | 919,000 | 924,000 | 947,000 | 971,000 | 996,000 |
| IDC (G) | 405,915 | 449,760 | 432,111 | 474,433 | 444,170 | 548,015 | 559,997 | 682,428 | 1,219,000[5] | 2,109,000[9] | 2,163,000 | 1,112,000 | 1,181,000 | 1,193,000 |
| Subtotal (H=E+F+G) | 29,693,808 | 33,525,552 | 32,486,207 | 35,829,621 | 37,396,779 | 45,733,316 | 40,640,712 | 53,981,712 | 90,637,000 | 102,102,000 | 105,887,000 | 102,971,000 | 102,725,000 | 103,264,000 |
| Less: Contributions (I) | (1,262,517) | (746,454) | (677,905) | (758,922) | (1,157,098) | (1,483,088) | (1,346,601) | (1,586,930) | (13,179,000)[6] | (8,550,000)[10] | (2,450,000) | (2,200,000) | (1,600,000) | (1,450,000) |
| **Net Capital Expenditures (J=H+I)** | **$ 28,431,291** | **$ 32,779,098** | **$ 31,808,302** | **$ 35,070,699** | **$ 36,239,681** | **$ 44,250,228** | **$ 39,294,111** | **$ 52,394,782** | **$ 77,458,000** | **$ 93,552,000** | **$ 103,437,000** | **$ 100,771,000** | **$ 101,125,000** | **$ 101,814,000** |

1 2023 Distribution total includes $385,628 for the AMI component of the Advanced Metering for Sustainable Electrification project, a submitted multi-year SCBR filing; therefore, it was not included in the 2023 Capital Budget Application.
2 2023 Corporate total includes $992,349 for the CIS component of the Advanced Metering for Sustainable Electrification project, a submitted multi-year SCBR filing; therefore, it was not included in the 2023 Capital Budget Application.
3 2024 Distribution total includes $17,107,000 for the AMI component of the Advanced Metering for Sustainable Electrification project, a submitted multi-year SCBR filing; therefore, it was not included in the 2024 Capital Budget Application.
4 2024 Corporate total includes $8,467,000 for the CIS component of the Advanced Metering for Sustainable Electrification project, a submitted multi-year SCBR filing; therefore, it was not included in the 2024 Capital Budget Application.
5 2024 IDC total includes $420,000 for the Advanced Metering for Sustainable Electrification project, a submitted multi-year SCBR filing; therefore, it was not included in the 2024 Capital Budget Application.
6 2024 Contributions total includes $12,000,000 for the Advanced Metering for Sustainable Electrification project, a submitted multi-year SCBR filing; therefore, it was not included in the 2024 Capital Budget Application.
7 2025 Distribution total includes $16,635,000 for the CIS component of the Advanced Metering for Sustainable Electrification project, a submitted multi-year SCBR filing; therefore, it is not included in the 2025 Capital Budget Application.
8 2025 Corporate total includes $7,495,000 for the CIS component of the Advanced Metering for Sustainable Electrification project, a submitted multi-year SCBR filing; therefore, it is not included in the 2025 Capital Budget Application.
9 2025 IDC total includes $1,240,000 for the Advanced Metering for Sustainable Electrification project, a submitted multi-year SCBR filing; therefore, it is not included in the 2025 Capital Budget Application.
10 2025 Contributions total includes $7,000,000 for the Advanced Metering for Sustainable Electrification project, a submitted multi-year SCBR filing; therefore, it is not included in the 2025 Capital Budget Application.

# APPENDIX B

## List of Future Capital Projects
## (2025 to 2029)

## List of Future Capital Projects (2025 to 2029)

| Project Description | 2025 BUDGET | 2026 FORECAST | 2027 FORECAST | 2028 FORECAST | 2029 FORECAST |
|---|---|---|---|---|---|
| **4.0 GENERATION** | | | | | |
| **4.1 - CGS Buildings and Site Services** | | | | | |
| CGS Miscellaneous Building and Site Upgrades | 52,000 | 39,000 | 40,000 | 42,000 | 43,000 |
| ECC Mechanical Upgrades and Electrical Assessment | 151,000 | | | | |
| CGS Entrance Improvements and Modifications | 68,000 | | | | |
| ECC Electrical Upgrades | - | 128,000 | | | |
| ECC SCADA Upgrades | - | | 282,000 | | |
| ECC Roof and Windows Replacement | - | | | 405,000 | |
| Machine Shop Upgrades | - | | | | 285,000 |
| ECC Entrance Vestibule and Facility Upgrades | - | | | | 102,000 |
| Other CGS Building and Site Services Projects | - | 212,000 | 219,000 | 225,000 | 232,000 |
| **Subtotal** | **$ 271,000** | **$ 379,000** | **$ 541,000** | **$ 672,000** | **$ 662,000** |
| **4.2 - CGS Turbine Generator** | | | | | |
| CGS Combustion Turbine Improvements, Parts and Tools | 180,000 | 192,000 | 198,000 | 204,000 | 210,000 |
| CT3 Spare and Replacement Parts | 258,000 | | | | |
| Reverse Osmosis Electrodeionization Equipment Upgrades | - | | 343,000 | | |
| CT3 Work Station Replacement | - | | | 421,000 | |
| Install Vibration Dampers on CT3 Auxiliary Equipment | - | | | | 147,000 |
| Other CGS Turbine Generator Projects | - | 212,000 | 219,000 | 563,000 | 580,000 |
| **Subtotal** | **$ 438,000** | **$ 404,000** | **$ 760,000** | **$ 1,188,000** | **$ 937,000** |
| **4.3 - BGS Buildings and Site Services** | | | | | |
| BGS Miscellaneous Building and Site Upgrades | 65,000 | 39,000 | 40,000 | 42,000 | 43,000 |
| **Subtotal** | **$ 65,000** | **$ 39,000** | **$ 40,000** | **$ 42,000** | **$ 43,000** |
| **4.4 - BGS Turbine Generators** | | | | | |
| BGS Combustion Turbine Improvements, Parts and Tools | 152,000 | 125,000 | 129,000 | 133,000 | 137,000 |
| CT1 Power Turbine Inspection | 211,000 | | | | |
| CT1 Power Turbine Nozzle Repair | - | 1,590,000 | 232,000 | | |
| CT1 Life Extension Upgrades | - | | 275,000 | | |
| CT1 Refurbishment at Depot | - | | | 909,000 | |
| Other BGS Turbine Generator Projects | - | 212,000 | 219,000 | 563,000 | 598,000 |
| **Subtotal** | **$ 363,000** | **$ 1,927,000** | **$ 855,000** | **$ 1,605,000** | **$ 735,000** |
| **SUBTOTAL GENERATION** | **$ 1,137,000** | **$ 2,749,000** | **$ 2,196,000** | **$ 3,507,000** | **$ 2,377,000** |
| **5.0 DISTRIBUTION** | | | | | |
| **5.1 - Replacements Due to Storms, Collisions, Fire and Road Alterations** | | | | | |
| Replacements Due to Storms, Collisions, and Fire | 1,236,000 | 1,281,000 | 1,314,000 | 1,348,000 | 1,383,000 |
| Replacements Due to Road Alterations | 988,000 | 1,126,000 | 1,156,000 | 1,186,000 | 1,217,000 |
| **Subtotal** | **$ 2,224,000** | **$ 2,407,000** | **$ 2,470,000** | **$ 2,534,000** | **$ 2,600,000** |
| **5.2 - Distribution Transformers** | | | | | |
| Polemount, Padmount and Stepdown Transformers | 15,154,000 | 19,234,000 | 22,619,000 | 21,778,000 | 23,565,000 |
| Spill Prevention Program | 754,000 | | | | |
| **Subtotal** | **$ 15,908,000** | **$ 19,234,000** | **$ 22,619,000** | **$ 21,778,000** | **$ 23,565,000** |
| **5.3 - Services and Street Lighting** | | | | | |
| Overhead and Underground Services | 9,110,000 | 10,169,000 | 9,481,000 | 9,726,000 | 9,977,000 |
| Street and Area Lighting | 592,000 | 612,000 | 629,000 | 646,000 | 664,000 |
| **Subtotal** | **$ 9,702,000** | **$ 10,781,000** | **$ 10,110,000** | **$ 10,372,000** | **$ 10,641,000** |
| **5.4 - Line Extensions** | | | | | |
| Customer Driven Line Extensions | 2,161,000 | 2,576,000 | 2,643,000 | 2,713,000 | 2,785,000 |
| **Load and Reliability Driven Line Extensions** | | | | | |
| Blue Shank Road Three Phase Conversion | 1,483,000 | | | | |
| Irishtown Road Three Phase Conversion | - | 1,082,000 | | | |
| Norwood Road Three Phase Conversion | - | 360,000 | | | |
| Mount Buchanan Line Extension and Partial Conversion | - | | 1,399,000 | | |
| Charlottetown Area Substation Feeders | - | | | 1,180,000 | |
| Barclay Road O'Leary Line Extension | - | | | | 586,000 |
| Dingwells Mills Substation Feeders | - | | | | 784,000 |
| **Subtotal** | **$ 3,644,000** | **$ 4,018,000** | **$ 4,042,000** | **$ 3,893,000** | **$ 4,155,000** |
| **5.5 Line Rebuilds** | | | | | |
| Distribution Line Refurbishment Program | 881,000 | 912,000 | 936,000 | 960,000 | 985,000 |
| Eastern Cedar Pole Replacement Program | 1,343,000 | 1,392,000 | 1,428,000 | 1,465,000 | 1,503,000 |
| Deteriorated Conductor Replacement Program | 445,000 | 461,000 | 946,000 | 971,000 | 996,000 |
| Backlot Feed Relocation Program | 489,000 | 506,000 | 520,000 | 534,000 | 548,000 |
| Distribution Corridor Widening | 887,000 | 920,000 | 943,000 | 967,000 | 991,000 |
| Satellite-Based Vegetation Imaging - Distribution | 396,000 | 95,000 | 97,000 | 100,000 | 102,000 |
| **Single and Three Phase Line Rebuilds** | | | | | |
| Alberton to Elmsdale Line Rebuild | 1,673,000 | | | | |
| Keppoch Road Line Rebuild | 699,000 | | | | |
| Kinross to Vernon River Line Rebuild | - | 1,056,000 | | | |
| Route 20 Malpeque Line Rebuild | - | | 1,011,000 | | |
| Cape Bear Road Line Rebuild | - | | | 1,374,000 | 1,431,000 |
| Green Road Bonshaw Line Rebuild | - | 402,000 | | | |
| Oak Drive Distribution Underbuild Rebuild | - | | | 983,000 | |
| Bunbury Road Line Rebuild | - | | | 1,604,000 | |
| Mount Edward Road Line Rebuild | - | | | | 1,723,000 |
| New Argyle Road Voltage Conversion | - | 170,000 | | | |
| Mount Buchahan Voltage Conversion | - | | 844,000 | | |
| York Point Road Voltage Conversion | - | | | | 378,000 |
| Line Road Albion Voltage Conversion | - | | | 466,000 | |
| Cavendish Distribution Automation | - | | | | 577,000 |
| **Subtotal** | **$ 6,813,000** | **$ 5,914,000** | **$ 6,725,000** | **$ 9,424,000** | **$ 9,234,000** |
| **5.6 - System Meters** | | | | | |
| Watt-Hour Meters | 565,000 | 586,000 | 602,000 | 619,000 | 636,000 |
| Combination Meters | 90,000 | 91,000 | 94,000 | 96,000 | 99,000 |
| Outdoor Metering Tanks | 110,000 | 81,000 | 83,000 | 85,000 | 88,000 |
| Miscellaneous Metering Equipment | 40,000 | 41,000 | 43,000 | 44,000 | 45,000 |
| **Subtotal** | **$ 805,000** | **$ 799,000** | **$ 822,000** | **$ 844,000** | **$ 868,000** |
| **5.7 - Distribution Equipment** | | | | | |
| Substation, Line and Communication Equipment | 1,042,000 | 1,115,000 | 1,147,000 | 1,180,000 | 1,214,000 |
| Relay Replacement Equipment | 184,000 | 178,000 | 184,000 | 189,000 | 194,000 |
| Switch Replacement Equipment | 71,000 | 117,000 | 120,000 | 124,000 | 127,000 |
| Line Tools and Equipment | 242,000 | 249,000 | 257,000 | 264,000 | 272,000 |
| Meter Shop Equipment | 34,000 | 35,000 | 36,000 | 37,000 | 38,000 |
| **Subtotal** | **$ 1,573,000** | **$ 1,694,000** | **$ 1,744,000** | **$ 1,794,000** | **$ 1,845,000** |

## List of Future Capital Projects (2025 to 2029)

| Project Description | 2025 BUDGET | 2026 FORECAST | 2027 FORECAST | 2028 FORECAST | 2029 FORECAST |
|---|---|---|---|---|---|
| **5.8 - Transportation Equipment** | | | | | |
| Line Operation Vehicles | 1,663,000 | 1,186,000 | 2,038,000 | 2,040,000 | 1,641,000 |
| Small Vehicles and Equipment | 1,440,000 | 1,958,000 | 812,000 | 1,318,000 | 1,479,000 |
| **Subtotal** | **$ 3,103,000** | **$ 3,144,000** | **$ 2,850,000** | **$ 3,358,000** | **$ 3,120,000** |
| **SUBTOTAL DISTRIBUTION** | **$ 43,772,000** | **$ 47,991,000** | **$ 51,382,000** | **$ 53,997,000** | **$ 56,028,000** |
| **6.0 TRANSMISSION** | | | | | |
| **6.1 - Substation Projects** | | | | | |
| Substation Oil Containment Program | 176,000 | 183,000 | 188,000 | 194,000 | 199,000 |
| Substation Modernization Program | 560,000 | 581,000 | 598,000 | 616,000 | 634,000 |
| 138 kV Breaker Replacement Program | 146,000 | 151,000 | 155,000 | 160,000 | 165,000 |
| Fibre Modifications Due to Road Alterations | 46,000 | 48,000 | 49,000 | 51,000 | 52,000 |
| Transmission Planning and Expansion Studies | - | 265,000 | 273,000 | 281,000 | 290,000 |
| Woodstock Switching Station | 5,161,000 | | | | |
| Lorne Valley Switching Station Expansion | 2,221,000 | 4,820,000 | | | |
| Sherbrooke X1 Autotransformer Replacement | 3,184,000 | 2,061,000 | | | |
| West Royalty Substation 13.8 kv Distribution Replacements | 1,777,000 | 4,278,000 | 6,619,000 | | |
| Scotchfort Substation | 872,000 | 9,405,000 | 5,917,000 | | |
| Charlottetown Grid Modernization | 200,000 | 2,000,000 | 1,500,000 | 300,000 | |
| Power Transformers | 3,943,000 | 2,937,000 | 3,055,000 | 4,889,000 | 7,047,000 |
| Dingwells Mills Substation | - | 303,000 | 3,222,000 | 3,588,000 | |
| West Royalty Substation Upgrade | - | | 3,210,000 | 3,339,000 | |
| Rattenburry Substation and 10 MVAR Capbank | - | | 312,000 | 4,130,000 | 3,903,000 |
| 69 kv and 138 kv Breakers | - | | | 601,000 | |
| Alberton Substation Upgrade | | | | 369,000 | 948,000 |
| Bedeque Reactor Replacement | - | | | 1,312,000 | 918,000 |
| Engineering Distribution Automation | - | | | 2,386,000 | 2,447,000 |
| Hunter River Substation | - | | | 321,000 | 3,427,000 |
| Mount Pleasant Substation | - | | | 321,000 | 3,427,000 |
| Woodstock Switching Station Capacitors | - | | | | 123,000 |
| New Eastern Substation | - | | | | 330,000 |
| **Substation Communcation Projects** | | | | | |
| Communication Fibre - Church Road to Souris | 1,279,000 | | | | |
| Communication Fibre - Y-106 Scotchfort to Lorne Valley | | 1,089,000 | | | |
| Communication Fibre - Woodstock to St Eleanor's | | | 2,519,000 | | |
| Communication Fibre - Lorne Valley to Victoria Cross and Borden to Albany | | | | 1,168,000 | |
| Communication Fibre - Lorne Valley to Georgetown and Bedeque to Richmond Cove | | | | | 1,180,000 |
| Communication Fibre - Victoria Cross to Dover | | | | | 1,180,000 |
| **Subtotal** | **$ 19,565,000** | **$ 28,121,000** | **$ 27,617,000** | **$ 24,026,000** | **$ 26,270,000** |
| **6.2 - Transmission Projects** | | | | | |
| 69 kV and 138 kV Switch Program | 1,186,000 | 949,000 | 974,000 | 1,000,000 | 1,027,000 |
| Transmission Line Refurbishment | 1,031,000 | 1,067,000 | 1,095,000 | 1,123,000 | 1,152,000 |
| Transmission Line Aerial Inspection | - | 28,000 | - | 30,000 | - |
| Transmission Corridor Widening | 381,000 | 395,000 | 405,000 | 415,000 | 426,000 |
| Satellite-Based Vegetation Imaging - Transmission | 132,000 | 31,000 | 32,000 | 33,000 | 33,000 |
| Y-106 Scotchfort to Lorne Valley | 3,192,000 | 1,707,000 | - | - | - |
| Woodstock Switching Station Transmission Modifications | 1,000,000 | - | - | - | - |
| Y-119 Extension to Scotchfort | 545,000 | 4,032,000 | 4,071,000 | 4,240,000 | - |
| Sherbrooke Autotransformer Transmission | - | 640,000 | - | - | - |
| Lorne Valley Transmission Modifications | - | 640,000 | - | - | - |
| Y-109 Bedeque to Bannockburn Road | - | - | 5,045,000 | 5,226,000 | - |
| Scotchfort Sub and Switching Station Transmission Modifications | - | | 421,000 | - | - |
| Dingwells Mills Substation Transmission Modifications | - | | | 1,364,000 | - |
| T-15 Sherwood | - | | | | 2,747,000 |
| Rattenbury Substation Transmission | - | | | | 1,579,000 |
| T-1 Reroute and Rebuild | - | | | | 4,395,000 |
| Transmission System Storm Hardening | - | | 716,000 | 665,000 | 700,000 |
| **Subtotal** | **$ 7,467,000** | **$ 9,489,000** | **$ 12,759,000** | **$ 14,096,000** | **$ 12,059,000** |
| **SUBTOTAL TRANSMISSION** | **$ 27,032,000** | **$ 37,610,000** | **$ 40,376,000** | **$ 38,122,000** | **$ 38,329,000** |
| **7.0 CORPORATE** | | | | | |
| **7.1 - Corporate Services** | | | | | |
| Recurring Annual Capital Requirements | 667,000 | 737,000 | 759,000 | 782,000 | 806,000 |
| Comprehensive Building Condition Assessment - 180 Kent Street | 205,000 | - | - | - | - |
| Comprehensive Building Condition Assessment - West Royalty Service Centre | - | 210,000 | - | - | - |
| Woodstock Service Centre | - | - | 862,000 | 1,104,000 | - |
| Other Corporate Services Projects | - | - | - | - | 566,000 |
| **Subtotal** | **$ 872,000** | **$ 947,000** | **$ 1,621,000** | **$ 1,886,000** | **$ 1,372,000** |
| **7.2 - Information Technology** | | | | | |
| Hardware Acquisitions | 832,000 | 849,000 | 874,000 | 923,000 | 946,000 |
| Purchased Software and Upgrades | 367,000 | 434,000 | 446,000 | 475,000 | 487,000 |
| Cybersecurity Enhancements | 643,000 | 733,000 | 784,000 | 770,000 | 790,000 |
| Customer Services and Communication Enhancements | - | 90,000 | 141,000 | 144,000 | 148,000 |
| Intranet Refresh | 116,000 | - | - | - | - |
| Great Plains Interface Upgrade | 81,000 | - | - | - | - |
| ECC Load Forecasting Tool | 92,000 | - | - | - | - |
| ESRI GIS Model Enhancements | - | 115,000 | - | - | - |
| Great Plains Upgrade | - | 232,000 | - | - | - |
| Utility Network Design Tool | - | 528,000 | 721,000 | - | - |
| Document Management | - | - | - | 152,000 | - |
| Energy Purchase System Refresh | - | - | - | 108,000 | - |
| Other IT Projects | - | - | - | 489,000 | 598,000 |
| **Subtotal** | **$ 2,131,000** | **$ 2,981,000** | **$ 2,966,000** | **$ 3,061,000** | **$ 2,969,000** |
| **SUBTOTAL CORPORATE** | **$ 3,003,000** | **$ 3,928,000** | **$ 4,587,000** | **$ 4,947,000** | **$ 4,341,000** |
| | | | | | |
| **TOTAL CAPITAL** | **$ 74,944,000** | **$ 92,278,000** | **$ 98,541,000** | **$ 100,573,000** | **$ 101,075,000** |
| **8.0 - Capitalized General Expense** | 919,000 | 924,000 | 947,000 | 971,000 | 996,000 |
| **9.0 - Interest During Construction** | 869,000 | 1,023,000 | 1,112,000 | 1,181,000 | 1,193,000 |
| **10.0 - Contributions in Aid of Construction** | (1,550,000) | (2,450,000) | (2,200,000) | (1,600,000) | (1,450,000) |
| **GRAND TOTAL CAPITAL** | **$ 75,182,000** | **$ 91,775,000** | **$ 98,400,000** | **$ 101,125,000** | **$ 101,814,000** |
| **SCBR - CIS/AMI CAPITAL FORECAST** | **$ 17,130,000** | **$ 10,522,000** | **$ 2,371,000** | **$ -** | **$ -** |
| **AMI IDC** | **$ 1,240,000** | **$ 1,140,000** | **$ -** | **$ -** | **$ -** |
| **TOTAL SCBR PROJECTS** | **$ 18,370,000** | **$ 11,662,000** | **$ 2,371,000** | **$ -** | **$ -** |
| **GRAND TOTAL CAPITAL WITH SCBR's INCLUDED** | **$ 93,552,000** | **$ 103,437,000** | **$ 100,771,000** | **$ 101,125,000** | **$ 101,814,000** |

# APPENDIX C

## Proposed 2025 Capital Expenditures by CEJC Classification
(2016 to 2029)

**Proposed 2025 Capital Expenditures by CEJC Classification**

| | Mandatory | Justifiable | Recurring | Work Support Services | Capitalized General Expense | Interest During Construction | TOTAL | % of Total Category Proposed |
|---|---|---|---|---|---|---|---|---|
| **4.0 Generation** | | | | | | | | |
| 4.1 Charlottetown Generating Station - Buildings and Site Services | | | | | | | | |
| a) CGS Miscellaneous Building and Site Upgrades | | | $ 52,000 | | | | | |
| b) ECC Mechanical Upgrades and Electrical Assessment | | $ 151,000 | | | | | | |
| c) CGS Entrance Improvements and Modifications | | 68,000 | | | | | | |
| Subtotal | - | 219,000 | 52,000 | - | - | - | $ 271,000 | 23.8% |
| 4.2 Charlottetown Generating Station - Turbine Generator | | | | | | | | |
| a) CGS Combustion Turbine Improvements, Parts and Tools | | | 180,000 | | | | | |
| b) CT3 Spare and Replacement Parts | | 258,000 | | | | | | |
| Subtotal | - | 258,000 | 180,000 | - | - | - | 438,000 | 38.5% |
| 4.3 Borden Generating Station - Buildings and Site Services | | | | | | | | |
| a) BGS Miscellaneous Building and Site Upgrades | | | 65,000 | | | | | |
| Subtotal | - | - | 65,000 | - | - | - | 65,000 | 5.7% |
| 4.4 Borden Generating Station - Turbine Generators | | | | | | | | |
| a) BGS Combustion Turbine Improvements, Parts and Tools | | | 152,000 | | | | | |
| b) CT1 Power Turbine Inspection | | 211,000 | | | | | | |
| Subtotal | - | 211,000 | 152,000 | - | - | - | 363,000 | 31.9% |
| **Generation Total** | **$ -** | **$ 688,000** | **$ 449,000** | **$ -** | **$ -** | **$ -** | **$ 1,137,000** | **100.0%** |
| **% of Total Category Proposed** | **0.0%** | **60.5%** | **39.5%** | **0.0%** | **0.0%** | **0.0%** | | **100.0%** |

**Proposed 2025 Capital Expenditures by CEJC Classification**

| | | Mandatory | Justifiable | Recurring | Work Support Services | Capitalized General Expense | Interest During Construction | TOTAL | % of Total Category Proposed |
|---|---|---|---|---|---|---|---|---|---|
| **5.0 Distribution** | | | | | | | | | |
| 5.1 Replacements Due to Storms, Collisions, Fire and Road Alterations | | | | | | | | | |
| a) Replacements Due to Storms, Collisions, and Fire | | | | $ 1,236,000 | | | | | |
| b) Replacements Due to Road Alterations | | | | 988,000 | | | | | |
| | Subtotal | - | - | 2,224,000 | - | - | - | $ 2,224,000 | 5.1% |
| 5.2 Distribution Transformers | | | | | | | | | |
| a) Polemount, Padmount and Stepdown Transformers | | | | 15,154,000 | | | | | |
| b) Spill Prevention Program | | $ 754,000 | | | | | | | |
| | Subtotal | 754,000 | - | 15,154,000 | - | - | - | 15,908,000 | 36.3% |
| 5.3 Services and Street Lighting | | | | | | | | | |
| a) Overhead and Underground Services | | | | 9,110,000 | | | | | |
| b) Street and Area Lighting Lighting | | | | 592,000 | | | | | |
| | Subtotal | - | - | 9,702,000 | - | - | - | 9,702,000 | 22.2% |
| 5.4 Line Extensions | | | | | | | | | |
| a) Customer Driven Line Extensions | | | | 2,161,000 | | | | | |
| b) Load and Reliability Driven Line Extensions | | | $ 1,483,000 | | | | | | |
| | Subtotal | - | 1,483,000 | 2,161,000 | - | - | - | 3,644,000 | 8.3% |
| 5.5 Line Rebuilds | | | | | | | | | |
| a) Single Phase and Three Phase Rebuilds | | | 2,372,000 | | | | | | |
| b) Distribution Line Refurbishment Program | | | | 881,000 | | | | | |
| c) Accelerated Distribution Component Replacement Program | | | 2,277,000 | | | | | | |
| d) Distribution Corridor Widening | | | | 887,000 | | | | | |
| e) Satellite-Based Vegetation Imaging - Distribution | | | | 396,000 | | | | | |
| | Subtotal | - | 4,649,000 | 2,164,000 | - | - | - | 6,813,000 | 15.6% |
| 5.6 System Meters | | | | | | | | | |
| a) Watt-Hour Meters | | | | 565,000 | | | | | |
| b) Combination Meters | | | | 90,000 | | | | | |
| c) Outdoor Metering Tanks | | | | 110,000 | | | | | |
| d) Miscellaneous Metering Equipment | | | | 40,000 | | | | | |
| | Subtotal | - | - | 805,000 | - | - | - | 805,000 | 1.8% |
| 5.7 Distribution Equipment | | | | | | | | | |
| a) Substation, Line and Communication Equipment | | | | 1,042,000 | | | | | |
| b) Relay Replacement Equipment | | | | 184,000 | | | | | |
| c) Switch Replacement Equipment | | | | 71,000 | | | | | |
| d) Line Tools and Equipment | | | | 242,000 | | | | | |
| e) Meter Shop Equipment | | | | 34,000 | | | | | |
| | Subtotal | - | - | 1,573,000 | - | - | - | 1,573,000 | 3.6% |
| 5.8 Transportation Equipment | Subtotal | - | - | - | 3,103,000 | - | - | 3,103,000 | 7.1% |
| | **Distribution Total** | **$ 754,000** | **$ 6,132,000** | **$ 33,783,000** | **$ 3,103,000** | **$ -** | **$ -** | **$ 43,772,000** | **100.0%** |
| | **% of Total Category Proposed** | **1.7%** | **14.0%** | **77.2%** | **7.1%** | **0.0%** | **0.0%** | | **100.0%** |

| Proposed 2025 Capital Expenditures by CEJC Classification | Mandatory | Justifiable | Recurring | Work Support Services | Capitalized General Expense | Interest During Construction | TOTAL | % of Total Category Proposed |
|---|---|---|---|---|---|---|---|---|
| **6.0 Transmission** | | | | | | | | |
| 6.1 Substation Projects | | | | | | | | |
| a) Woodstock Switching Station | | $ 5,161,000 | | | | | | |
| b) Lorne Valley Switching Station Expansion | | 2,221,000 | | | | | | |
| c) Sherbrooke X1 Autotransformer Replacement | | 3,184,000 | | | | | | |
| d) West Royalty Substation 13.8 kV Distribution Replacements | | 1,777,000 | | | | | | |
| e) Scotchfort Substation | | 872,000 | | | | | | |
| f) Power Transformers | | 3,943,000 | | | | | | |
| g) Substation Oil Containment Program | $ 176,000 | | | | | | | |
| h) Substation Modernization Program | | 560,000 | | | | | | |
| i) 138 kV Breaker Replacement Program | | 146,000 | | | | | | |
| j) Charlottetown Grid Modernization | | 200,000 | | | | | | |
| k) Communication Fibre - Church Road to Souris | | 1,279,000 | | | | | | |
| l) Fibre Modifications due to Road Alterations | | | $ 46,000 | | | | | |
| Subtotal | 176,000 | 19,343,000 | 46,000 | - | - | - | $ 19,565,000 | 72.4% |
| 6.2 Transmission Projects | | | | | | | | |
| a) 69 kV and 138 kV Switch Program | | | 1,186,000 | | | | | |
| b) Transmission Line Refurbishment Program | | | 1,031,000 | | | | | |
| c) Transmission Lines | | 4,737,000 | | | | | | |
| d) Transmission Corridor Widening | | | 381,000 | | | | | |
| e) Satellite-Based Vegetation Imaging - Transmission | | | 132,000 | | | | | |
| Subtotal | - | 4,737,000 | 2,730,000 | - | - | - | 7,467,000 | 27.6% |
| **Transmission Total** | **$ 176,000** | **$ 24,080,000** | **$ 2,776,000** | **$ -** | **$ -** | **$ -** | **$ 27,032,000** | **100.0%** |
| **% of Total Category Proposed** | **0.7%** | **89.1%** | **10.3%** | **0.0%** | **0.0%** | **0.0%** | | **100.0%** |
| **7.0 Corporate** | | | | | | | | |
| 7.1 Corporate Services | | | | | | | | |
| a) Annual Capital Requirements | | | | 667,000 | | | | |
| b) Comprehensive Building Condition Assessment - 180 Kent Street | | | | 205,000 | | | | |
| Subtotal | - | - | - | 872,000 | - | - | 872,000 | 29.0% |
| 7.2 Information Technology | | | | | | | | |
| a) Hardware Acquisitions | | | | 832,000 | | | | |
| b) Purchased Software and Upgrades | | | | 367,000 | | | | |
| c) Cybersecurity Enhancements | | | | 643,000 | | | | |
| d) Intranet Refresh | | | | 116,000 | | | | |
| e) Great Plains Interface Upgrade | | | | 81,000 | | | | |
| f) ECC Load Forcasting Tool | | | | 92,000 | | | | |
| Subtotal | - | - | - | 2,131,000 | - | - | 2,131,000 | 71.0% |
| **Corporate Total** | **$ -** | **$ -** | **$ -** | **$ 3,003,000** | **$ -** | **$ -** | **$ 3,003,000** | **100.0%** |
| **% of Total Category Proposed** | **0.0%** | **0.0%** | **0.0%** | **100.0%** | **0.0%** | **0.0%** | | **100.0%** |
| **Subtotal** | **$ 930,000** | **$ 30,900,000** | **$ 37,008,000** | **$ 6,106,000** | **$ -** | **$ -** | **$ 74,944,000** | |

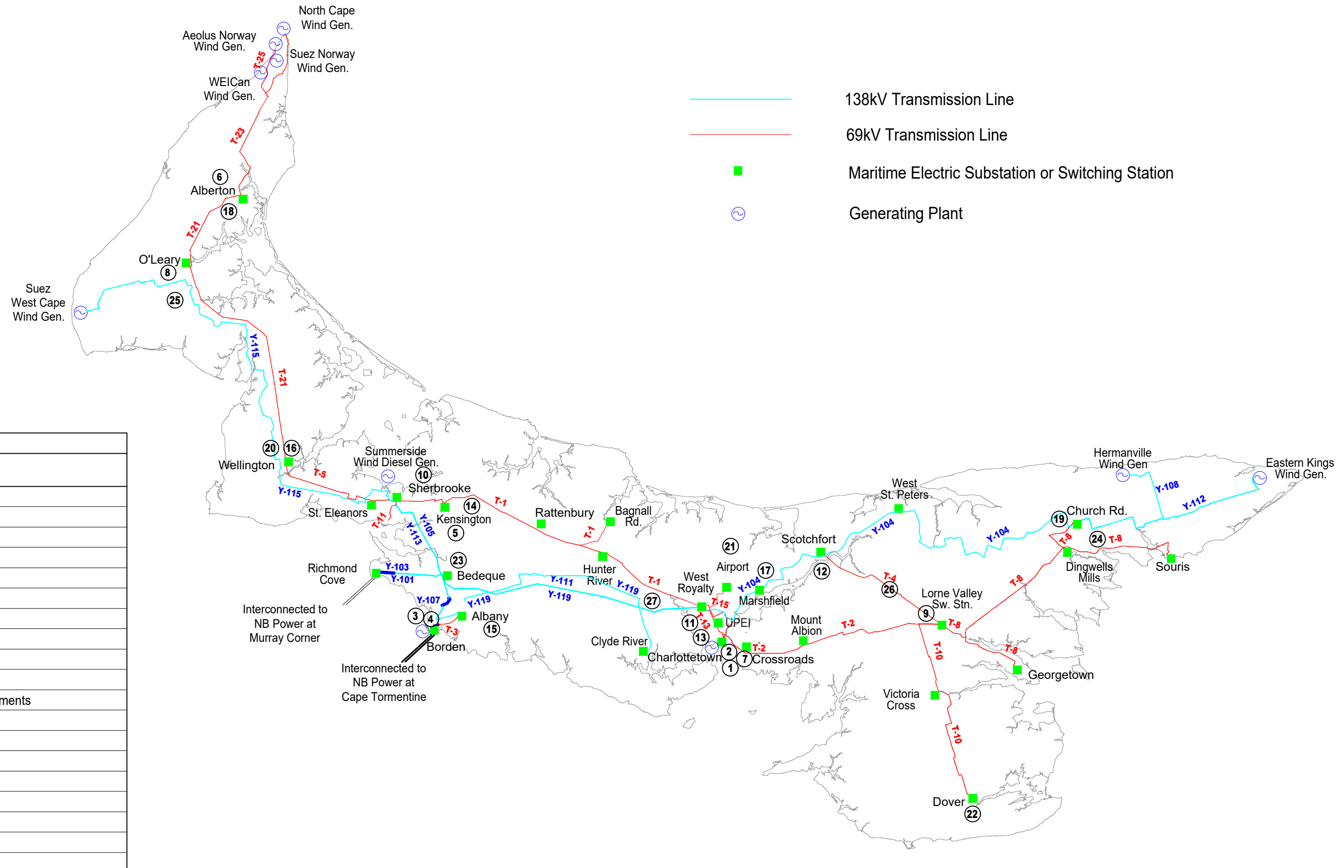
## Proposed 2025 Capital Expenditures by CEJC Classification

| | Mandatory | Justifiable | Recurring | Work Support Services | Capitalized General Expense | Interest During Construction | TOTAL | % of Total Category Proposed |
|---|---|---|---|---|---|---|---|---|
| **8.0 Capitalized General Expense** | | | | | $ 919,000 | | 919,000 | |
| **9.0 Interest During Construction** | | | | | | $ 869,000 | 869,000 | |
| **TOTAL** | **$ 930,000** | **$ 30,900,000** | **$ 37,008,000** | **$ 6,106,000** | **$ 919,000** | **$ 869,000** | **$ 76,732,000** | |
| **% of Total Proposed** | **1%** | **40%** | **49%** | **8%** | **1%** | **1%** | | |
| Customer Contributions | | | | | | | (1,550,000) | |
| **TOTAL (less Customer Contributions)** | | | | | | | **$ 75,182,000** | |

# APPENDIX D

## 2025 Capital Budget Project Locations

# 2025 CAPITAL BUDGET PROJECT LOCATIONS




| LEGEND OF PROJECT LOCATIONS ON MAP | | |
|---|---|---|
| Map Location | Budget Category | Project Description |
| 1 | 4.1 | CGS Buildings and Site Services Projects |
| 2 | 4.2 | CGS Turbine Generator Projects |
| 3 | 4.3 | BGS Buildings and Site Services Projects |
| 4 | 4.4 | BGS Turbine Generator Projects |
| 5 | 5.4b | Blue Shank Road Three Phase Conversion |
| 6 | 5.5a(i) | Alberton to Elmsdale Line Rebuild |
| 7 | 5.5a(ii) | Keppoch Road Line Rebuild |
| 8 | 6.1a | Woodstock Switching Station |
| 9 | 6.1b | Lorne Valley Switching Station Expansion |
| 10 | 6.1c | Sherbrooke X1 Autotransformer Replacement |
| 11 | 6.1d | West Royalty Substation13.8kV Distribution Replacements |
| 12 | 6.1e | Scotchfort Substation |
| 13 | 6.1f | Charlottetown Grid Modernization |
| 14 | 6.1g(i) | Kensington Power Transformer |
| 15 | 6.1g(ii) | Albany Power Transformer |
| 16 | 6.1g(iii) | Wellington Power Transformer |
| 17 | 6.1g(iv) | Marshfield Power Transformer |
| 18 | 6.1g(v) | Alberton Power Transformer |
| 19 | 6.1h | Substation Oil Containment Program |
| 20 | 6.1i(i) | Backup Generator System |
| 21 | 6.1i(ii) | Security Cameras |
| 22 | 6.1i(iii) | Mobile Transformer Accommodation |
| 23 | 6.1j | 138kV Breaker Replacement Program |
| 24 | 6.1k | Communication Fibre - Church Road to Souris |
| 25 | 6.2c(i) | Woodstock Switching Station Transmission Modifications |
| 26 | 6.2c(ii) | Y-106 Scotchfort to Lorne Valley |
| 27 | 6.2c(iii) | Y-119 Extension to Scotchfort |

MARITIME ELECTRIC
ELECTRICAL SYSTEM
PRINCE EDWARD ISLAND

# APPENDIX E

## Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

## Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

| Depreciation (000s) | Reference | Annual |
|---|---|---|
| **Depreciation Expense** | | |
| Capital Investment per Table 1, Proposed 2025 Capital Expenditures | A = $75,182 + $1,550 | 76,732 |
| Retirements (Note 1) | B = (A X 20%) | (15,346) |
| Plant Investment for Depreciation | C = A + B | $ 61,386 |
| Depreciation Rate (Note 2) | D | 3.61% |
| Depreciation Expense | E = C X D | $ 2,215 |
| **Capital Investment** | | |
| Capital Investment | A | 76,732 |
| Less: Customer Contributions per Table 1, Proposed 2023 Capital Expenditures | F | (1,550) |
| Total Capital Investment | G = A + F | $ 75,182 |
| **Accumulated Depreciation** | | |
| Costs of Removal (Note 3) | H = A / (1-17%) X 17% | (15,716) |
| Depreciation & Amortization | E | 2,215 |
| Total Change in Accumulated Depreciation | I = H + E | $ (13,501) |
| **Net Book Value (NBV) - Plant Investment** | **J = C - I** | **$ 74,886** |
| **Customer Contributions** | | |
| Customer Contributions per Table 1, Proposed 2024 Capital Expenditures | F | **$ (1,550)** |
| **Depreciation Expense - Contributions** | | |
| Annual Contributions | F | $ (1,550) |
| Depreciation Rate (Note 4) | K | 3.54% |
| Amortization of Customer Contributions | L = F X K | $ (55) |
| **Net Book Value (NBV) - Customer Contributions** | **M = F - L** | **$ (1,495)** |
| **Total Depreciation Expense (Net of Contributions)** | **N = E + L** | **$ 2,160** |

Note 1: Asset retirements estimated at 20% of capital expenditures based on average for 2018-2020.

Note 2: 2023 composite depreciation rate per 2020 Depreciation Study as per the GRA.

Note 3: Costs of Removal are estimated to be 17% of total capital investment and costs of removal based on average for 2018-2020.

Note 4: Distribution Contributions are depreciated using the rate per 2020 Depreciation Study for Distribution Service Lines.

## Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

| **Income Taxes (000s)** | **Reference** | | **Annual** |
|---|---|---|---|
| **Capital Cost Allowance** | | | |
| Capital Investment per Table 1, Proposed 2025 Capital Expenditures | A = $75,182 | | 75,182 |
| | | | |
| UCC for Calculation (Accelerated Investment Incentive) | A | | 75,182 |
| Capital Cost Allowance ("CCA") Rate (assumes class 47 ) | B | | 8.00% |
| CCA (Accelerated Investment Incentive @ 150%) | C = A X B X 150% | | 9,022 |
| | | | |
| Ending UCC | D = A - C | $ | 66,160 |
| | | | |
| **Future Income Taxes** | | | |
| CCA | C | $ | 9,022 |
| Less: Depreciation | E = N from Page 1 | | (2,160) |
| Cost of Removal & Operating deducted immediately for Tax | | | 15,716 |
| Difference CCA/Depreciation | F = C - E | | 22,578 |
| Future Tax Rate | G | | 31.00% |
| Future Income Taxes | H = F X G | | 6,999 |
| | | | |
| **Income Tax Effects of Increased Return** | | | |
| Return on Rate Base | I = H from Page 3 | $ | 4,527 |
| | | | |
| Tax Gross Up on Equity Return | K = G from Page 3 / (1-G) | | 1,138 |
| Debt Return | K = F from Page 3 | | (1,995) |
| | L = J + K | $ | 3,670 |
| | | | |
| **Income Tax Calculation** | | | |
| Return on Rate Base | L | $ | 3,670 |
| Add: Depreciation | E | | 2,160 |
| Less: CCA | C | | (9,022) |
| Less: Cost of Removal deducted immediately for tax | | | (15,716) |
| | M = L + E + C | | (18,908) |
| Corporate Tax Rate | G | | 31.00% |
| Current Income Taxes | N = M X G | | (5,862) |
| Future Income Taxes | H | | 6,999 |
| **Total Income Tax Expense** | **O = N + H** | **$** | **1,137** |

## Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

| Rate Base & Cost of Capital (000s) | Reference | | Annual |
|---|---|---|---|
| Net Book Value, Capital Investment | A = J from Page 1 | $ | 74,886 |
| Net Book Value, Contributions | B = M from Page 1 | | (1,495) |
| Future Income Taxes | C = H from Page 2 | | (6,999) |
| **Projected Rate Base** | **D = A + B + C** | **$** | **66,392** |
| | | | |
| **% of 2025 Forecast Year End Rate Base** | **E = D / R** | | **12.35%** |
| | | | |
| Return on Debt | F = D X O | $ | 1,995 |
| Return on Common Equity | G = D X P | | 2,532 |
| Total Return On Rate Base | H = F + G | $ | 4,527 |
| | | | |
| **Weighted Average Cost of Capital ("WACC")** | | | |
| Debt | I | | 60.0% |
| Common Equity | J | | 40.0% |
| | | | |
| Cost of Debt | K | | 4.92% |
| Cost of Common Equity | L | | 9.35% |
| | | | |
| Forecast 2025 Average Capitalization (Total Debt plus Common Equity) | M | | 529,652,800 |
| Forecast 2025 Average Rate Base* | N | | 519,857,100 |
| | | | |
| WA Cost of Debt | O = I X K X M/ N | | 3.01% |
| WA Cost of Common Equity | P = J X L X M/ N | | 3.81% |
| Forecast 2025 WACC | Q = O + P | | 6.82% |
| | | | |
| **2025 Forecast Year End Rate Base *** | **R** | **$** | **537,615** |

* Per Table 6-2 of the negotiated settlement of the GRA.

## Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

| Annual Project Revenue Requirement (000s) | Reference | | Annual |
|---|---|---|---|
| Depreciation | A = N from Page 1 | $ | 2,160 |
| Return on Debt | B = F from Page 3 | | 1,995 |
| Return on Equity | C = G from Page 3 | | 2,532 |
| Income Taxes | D = O from Page 2 | | 1,137 |
| **Estimated Annual Project Revenue Requirement** | **E = A + B + C + D** | **$** | **7,825** |
| **% of 2025 Forecast Revenue Requirement** | **F = E / G** | | **2.88%** |
| **Forecast 2025 Revenue Requirement*** | **G** | **$** | **271,927** |

* 2025 revenue requirement per Table 6-6 of the GRA is $260,577.

**Estimated Impact on Rate Base, Revenue Requirement and Customer Rates**

| Project Rate Impact | Reference | Annual |
|---|---|---|
| Total Project Revenue Requirement | A = E from Page 4 X 1000 | $ 7,825,277 |
| Forecast 2025 kWh Sales * | B | 1,606,372,142 |
| **Forecast Increase Per kWh Project Rate Impact** | **C = A / B** | **$ 0.00487** |
| **Forecast Increase Annual Cost Benchmark Residential Customer (650 kWh per month) before tax** | **D = 650 kWh X C X 12 months** | **$ 37.99** |
| % of 2025 Forecast Annual Cost for Rural Residential Customer | E = D / I | 2.29% |
| % of 2025 Forecast Annual Cost for Urban Residential Customer | F = D / J | 2.33% |
| **Forecast Increase Annual Cost Benchmark General Service Customer (10,000 kWh per month) before tax** | **G = 10,000 kWh X C X 12 months** | **$ 584.40** |
| % of 2025 Forecast Annual Cost for General Service Customer | H = G / K | 2.25% |
| 2025/2026 Forecast Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per Table 7-4 of GRA negotiated settlement agreement reached with the Commission on April 24, 2023. | I | $1,658.67 |
| 2025/2026 Forecast Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per Table 7-5 of GRA negotiated settlement agreement reached with the Commission on April 24, 2023. | J | $ 1,630.47 |
| 2025 Forecast Annual Cost Benchmark General Service Customer (10,000 kWh per month) excluding tax per Table 7-6 of GRA negotiated settlement agreement reached with the Commission on April 24, 2023. | K | $ 26,001.74 |

* Forecast 2025 kWh sales based on current load forecast at the time of filing this application.

# APPENDIX F

## Proposed 2025 Capital Expenditures by Investment Classification

## Proposed 2025 Capital Expenditures by Investment Classification

| | Mandatory | Access | System Growth | Renewal | Service Enhancement | General Plant | TOTAL |
|---|---|---|---|---|---|---|---|
| **4.0 Generation** | | | | | | | |
| 4.1 Charlottetown Generating Station - Buildings and Site Services | | | | | | | |
| a) CGS Miscellaneous Building and Site Upgrades | | | | | | $ 52,000 | |
| b) ECC Mechanical Upgrades and Electrical Assessment | | | | $ 151,000 | | | |
| c) CGS Entrance Improvements and Modifications | | | | | | 68,000 | |
| Subtotal | - | - | - | 151,000 | - | 120,000 | $ 271,000 |
| 4.2 Charlottetown Generating Station - Turbine Generator | | | | | | | |
| a) CGS Combustion Turbine Improvements, Parts and Tools | | | | 180,000 | | | |
| b) CT3 Spare and Replacement Parts | | | | 258,000 | | | |
| Subtotal | - | - | - | 438,000 | - | - | 438,000 |
| 4.3 Borden Generating Station - Buildings and Site Services | | | | | | | |
| a) BGS Miscellaneous Building and Site Upgrades | | | | | | 65,000 | |
| Subtotal | - | - | - | - | - | 65,000 | 65,000 |
| 4.4 Borden Generating Station - Turbine Generators | | | | | | | |
| a) BGS Combustion Turbine Improvements, Parts and Tools | | | | 152,000 | | | |
| b) CT1 Power Turbine Inspection | | | | 211,000 | | | |
| Subtotal | - | - | - | 363,000 | - | - | 363,000 |
| **Generation Total** | **$ -** | **$ -** | **$ -** | **$ 952,000** | **$ -** | **$ 185,000** | **$ 1,137,000** |
| **% of Generation Total By Investment Category** | **0.0%** | **0.0%** | **0.0%** | **83.7%** | **0.0%** | **16.3%** | |
| **5.0 Distribution** | | | | | | | |
| 5.1 Replacements Due to Storms, Collisions, Fire and Road Alterations | | | | | | | |
| a) Replacements Due to Storms, Collisions, and Fire | | | | $ 1,236,000 | | | |
| b) Replacements Due to Road Alterations | | $ 988,000 | | | | | |
| Subtotal | - | 988,000 | - | 1,236,000 | - | - | $ 2,224,000 |
| 5.2 Distribution Transformers | | | | | | | |
| a) Polemount, Padmount and Stepdown Transformers | | 7,577,000 | | 7,577,000 | | | |
| b) Spill Prevention Program | $ 754,000 | | | | | | |
| Subtotal | 754,000 | 7,577,000 | - | 7,577,000 | - | - | 15,908,000 |
| 5.3 Services and Street Lighting | | | | | | | |
| a) Overhead and Underground Services | | $ 9,110,000 | | | | | |
| b) Street and Area Lighting Lighting | | $ 592,000 | | | | | |
| Subtotal | - | 9,702,000 | - | - | - | - | 9,702,000 |
| 5.4 Line Extensions | | | | | | | |
| a) Customer Driven Line Extensions | | 2,161,000 | | | | | |
| b) Reliability Driven Line Extensions | | | | | $ 1,483,000 | | |
| Subtotal | - | 2,161,000 | - | - | 1,483,000 | - | 3,644,000 |
| 5.5 Line Rebuilds | | | | | | | |
| a) Single Phase and Three Phase Rebuilds | | | | 2,372,000 | | | |
| b) Distribution Line Refurbishment Program | | | | 881,000 | | | |
| c) Accelerated Distribution Component Replacement Program | | | | 2,277,000 | | | |
| d) Distribution Corridor Widening | | | | | 887,000 | | |
| e) Satellite-Based Vegetation Imaging - Distribution | | | | | 396,000 | | |
| Subtotal | - | - | - | 5,530,000 | 1,283,000 | - | 6,813,000 |
| 5.6 System Meters | | | | | | | |
| a) Watt-Hour Meters | | 361,600 | | 203,400 | | | |
| b) Combination Meters | | 57,600 | | 32,400 | | | |
| c) Outdoor Metering Tanks | | | | 110,000 | | | |
| d) Miscellaneous Metering Equipment | | | | 40,000 | | | |
| Subtotal | - | 419,200 | - | 385,800 | - | - | 805,000 |
| 5.7 Distribution Equipment | | | | | | | |
| a) Substation, Line and Communication Equipment | | | | 1,042,000 | | | |
| b) Relay Replacement Equipment | | | | 184,000 | | | |
| c) Switch Replacement Equipment | | | | 71,000 | | | |
| d) Line Tools and Equipment | | | | | | $ 242,000 | |
| e) Meter Shop Equipment | | | | | | 34,000 | |
| Subtotal | - | - | - | 1,297,000 | - | 276,000 | 1,573,000 |
| 5.8 Transportation Equipment Subtotal | - | - | - | | - | 3,103,000 | 3,103,000 |
| **Distribution Total** | **$ 754,000** | **$ 20,847,200** | **$ -** | **$ 16,025,800** | **$ 2,766,000** | **$ 3,379,000** | **$ 43,772,000** |
| **% of Distribution Total By Investment Category** | **1.7%** | **47.6%** | **0.0%** | **36.6%** | **6.3%** | **7.7%** | |
| **6.0 Transmission** | | | | | | | |
| 6.1 Substation Projects | | | | | | | |
| a) Woodstock Switching Station | | | | | $ 5,161,000 | | |
| b) Lorne Valley Switching Station Expansion | | | $ 2,221,000 | | | | |
| c) Sherbrooke X1 Autotransformer Replacement | | | | $ 3,184,000 | | | |
| d) West Royalty Substation 13.8 kV Distribution Replacements | | | | 1,777,000 | | | |
| e) Scotchfort Substation | | | 523,200 | 348,800 | | | |
| f) Power Transformers | | | 2,365,800 | 1,577,200 | | | |
| g) Substation Oil Containment Program | $ 176,000 | | | | | | |
| h) Substation Modernization Program | | | | 560,000 | | | |
| i) 138 kV Breaker Replacement Program | | | | 146,000 | | | |
| j) Charlottetown Grid Modernization | | | | 200,000 | | | |
| k) Communication Fibre - Church Road to Souris | | | | | 1,279,000 | | |
| l) Fibre Modifications due to Road Alterations | | $ 46,000 | | | | | |
| Subtotal | 176,000 | 46,000 | 5,110,000 | 7,793,000 | 6,440,000 | - | $ 19,565,000 |
| 6.2 Transmission Projects | | | | | | | |
| a) 69 kV and 138 kV Switch Program | | | | 1,186,000 | | | |
| b) Transmission Line Refurbishment Program | | | | 1,031,000 | | | |
| c) Transmission Lines | | | 545,000 | 3,192,000 | 1,000,000 | | |
| d) Transmission Corridor Widening | | | | | 381,000 | | |
| e) Satellite-Based Vegetation Imaging - Transmission | | | | | 132,000 | | |
| Subtotal | - | - | 545,000 | 5,409,000 | 1,513,000 | - | 7,467,000 |
| **Transmission Total** | **$ 176,000** | **$ 46,000** | **$ 5,655,000** | **$ 13,202,000** | **$ 7,953,000** | **$ -** | **$ 27,032,000** |
| **% of Transmission Total By Investment Category** | **0.7%** | **0.2%** | **20.9%** | **48.8%** | **29.4%** | **0.0%** | |
| **7.0 Corporate** | | | | | | | |
| 7.1 Corporate Services | | | | | | | |
| a) Annual Capital Requirements | | | | | | $ 667,000 | |
| b) Comprehensive Building Condition Assessment - 180 Kent Street | | | | | | 205,000 | |
| Subtotal | - | - | - | - | - | 872,000 | $ 872,000 |
| 7.2 Information Technology | | | | | | | |
| a) Hardware Acquisitions | | | | | | 832,000 | |
| b) Purchased Software and Upgrades | | | | | | 367,000 | |
| c) Cybersecurity Enhancements | | | | | | 643,000 | |
| d) Intranet Refresh | | | | | | 116,000 | |
| e) Great Plains Interface Upgrade | | | | | | 81,000 | |
| f) ECC Load Forcasting Tool | | | | | | 92,000 | |
| Subtotal | - | - | - | - | - | 2,131,000 | 2,131,000 |
| **Corporate Total** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 3,003,000** | **$ 3,003,000** |
| **% of Corporate Total By Investment Category** | **0.0%** | **0.0%** | **0.0%** | **0.0%** | **0.0%** | **100.0%** | |
| **TOTAL** | **$ 930,000** | **$ 20,893,200** | **$ 5,655,000** | **$ 30,179,800** | **$ 10,719,000** | **$ 6,567,000** | **$ 74,944,000** |
| **% of Total** | **1%** | **28%** | **8%** | **40%** | **15%** | **8%** | **100%** |

# APPENDIX G

## Accounting Manual

## Account Number Master

Issued - April 2021

### Department

**Financial**
- 10 Production
- 12 Energy Control Centre
- 24 Line
- 25 Customer Service
- 27 Meter Reading
- 30 Operations Metering
- 32 Operations Engineering
- 34 Operations Construction Services
- 36 Operations Systems Maintenance
- 41 Finance
- 45 Information Technology
- 50 Stores
- 51 Office Services
- 52 Regulatory Planning
- 55 Corporate Communication
- 60 Human Resources
- 61 Internal Audit
- 62 Health Safety and Environmental
- 65 Corporate Planning
- 70 Executive

**Banking**
- 80 Scotiabank
- 81 CIBC
- 82 USD
- 83 Tignish Credit Union
- 84 Morell Credit Union
- 85 Royal Bank

**OATT**
- 90 OATT - MECL
- 91 OATT - COS
- 92 OATT - WC
- 93 OATT - Emera
- 94 OATT - WC to MECL

**kWh/NPP**
- NF Non-Financial

### Project Codes

**Capital Work Orders**

**Distribution**
- 70200 Replacement due to Storms, Road Alterations
- 70361 Storm Replacements
- 70248 Road / Bridge Work - DOT
- 70202 Distribution Transformers
- 70212 Distribution Transformers - Spill Prevention
- 70203 Services and Street Lighting
- 70351 LED Lighting Program
- 70204 Line Extensions
- 70205 Line Rebuilds
- 70396 Distribution Line Refurbishment
- 70276 Porcelain Cutout Replacements
- 70423 Cedar Pole Replacement Program
- 70206 System Meters
- 70207 Distribution Equipment
- 70270 Teleprotection and Relay Replacement
- 70304 Distribution Switches
- 70273 Meter Shop Equipment
- 70274 Line Tools and Equipment
- 90141 Transportation Equipment

**Transmission**
- 80220 Substation Projects
- 80841 Substation Modernization Program
- 80844 138kV Breaker Replacement Program
- 80219 Line Projects
- 80762 69kV and 138kV Switch Maintenance
- 80811 Transmission Line Refurbishment

***Retirement**
- 10612 Retire CTGS Decommissioning Study
- 70600 Retire Distribution Poles and Fixtures
- 70601 Retire Distribution Overhead and U/G Cables and Conduits
- 70602 Retire Overhead and U/G Service Lines
- 70603 Retire Overhead and U/G Street Lights
- 70604 Retire System Meters
- 70605 Retire Transformers
- 70608 Retire Distribution and Transmission Substaion Equipment
- 70609 Retire Line Tools
- 70613 Retire aDist Line Control Devices
- 70616 Retire Transportation
- 70617 Retire Office Equipment
- 70623 Retire Communication
- 80600 Retire Transmission Poles and Fixtures
- 80601 Retire Transmissiion Overhead Conductor
- 80608 Retire Substation
- 80613 Retire Transmission Line Control Devices

**OATT Charges**
- 80911 T-11
- 80912 Y-112
- 80927 Y-115
- 80932 Borden Substation
- 80936 WR Substation - OATT Assets
- 80937 WR Substation - Dist Assets
- 80938 Sherbrooke Substation - OATT Assets

*** These work orders are to be used only if there is no Capital Work Order associated with the retirement. Account should begin with a 5.**

### Account Type
- 1 Property, Plant and Equipment
- 2 Capital
- 3 Accounts Receivable / Vehicle Expense
- 5 Retirement
- 7 Operating Transmission and Distribution
- 8 Operating General Expenses

### Location
- 1 Plant
- 2 Borden Generation Station
- 3 Energy Control Centre
- 4 MICF
- 7 Distribution Line
- 8 Transmission Line

### Activity
- 01 Plant Land
- 02 Plant Build
- 03 Pumphouse Elect Equip
- 04 Pumphouse Mech Equip
- 05 Boiler Plant Equip
- 07 Turbine & Aux Equip
- 09 Gas Turbine & Aux Equip
- 13 Elect Equip Plant
- 15 Misc Plant Equip
- 16 Superintendance
- 17 Fuel
- 35 Shop Equip
- 39 Pumphouse Build
- 80 Training
- 01 Borden Plant Land
- 02 Borden Build
- 09 Borden Gas Turbine & Aux Equip
- 15 Borden Misc Equip
- 16 Maintenance
- 01 ECC Land
- 15 ECC Misc Plant Equip
- 50 Insurance
- 55 Property Taxes
- 79 ECC Build
- 40 Dist Sub Land
- 41 Dist Sub Equip Build & Struct
- 44 Dist Land
- 48 Dist OH Cond
- 49 Dist Poles & Fixtures
- 50 Dist Line Control Devices
- 51 Dist Trans
- 52 Dist Trans Installations
- 53 Dist Service Lines
- 54 Dist Street & Yard Lights
- 55 Dist UG Conductors
- 56 Dist UG Service Lines
- 57 Dist UG Street Lights
- 58 Dist Meters
- 59 Dist Meter Install
- 60 Dist Communications
- 61 Dist Eng & Survey Equip
- 62 Dist Tools & Stores Equip
- 63 Scada System
- 77 Dist Gen Prop Land
- 78 Dist Gen Prop Build Office
- 79 Dist Gen Prop Build Districts
- 80 Office Equip
- 81 Transportation Equip
- 84 Computer Hardware
- 85 Computer Software
- 86 Marketing & Transition
- 40 Trans Sub Land
- 41 Trans Sub Equip, Build & Struc
- 44 Trans Land
- 46 Road & Trails
- 47 Trans Towers
- 48 Trans OH Cond
- 49 Trans Poles & Fixtures
- 50 Trans Line Control Devices
- 55 Trans UG Cables
- 77 Trans Gen Prop Land

### Expense Type
- 10 Labour - Regular Salary
- 11 Labour - Regular Hourly
- 12 Labour - Overtime Salary
- 13 Labour - Overtime Hourly
- 14 Labour - Doubletime Salary
- 15 Labour - Doubletime Hourly
- 16 Labour - Outside
- 17 Labour - Flagging
- 20 Mileage - Fleet
- 30 Materials
- 32 Energy / Fuel Supply
- 36 Stores (Inventory Only)
- 38 Salvage of Materials
- 39 Retirement of Assets
- 40 Consultants Fees
- 45 Legal Fees
- 47 Professional Fees
- 60 Marketing / Advertising
- 70 General Expenses
- 71 Communications
- 72 Reproduction Printing Stationary
- 73 Equipment Lease and Rentals
- 74 Maintenance Agreements
- 75 Meals and Entertainment
- 76 General Administrative Expenses
- 77 Replacement Repair & Building Costs
- 78 Postage
- 80 Accomodations and Travel Charges
- 82 Membership and Subscription Charges
- 83 Professional Dues, Corporate License Reg
- 85 Trustee Stock Exchnage Fees
- 86 Employee Assistance Program
- 90 Miscellaneous Programs
- 91 Computer Hardware
- 92 Computer Software

Department | Project | Account | Expense Type

Cost of Service Utility Accounting - Construction Accounting Instructions

| PROPERTY, PLANT AND EQUIPMENT ACCOUNTING | | |
|---|---|---|
| **PRODUCTION** | | |
| **Account Name** | **Section** | **Account Number** |
| Land | Charlottetown<br>Borden | 1101<br>1201 |
| Buildings and Structure | Charlottetown<br>Borden | 1102<br>1202 |
| Pumphouse – Mechanical Equipment | Charlottetown | 1103 |
| Pumphouse – Electrical Equipment | Charlottetown | 1104 |
| Steam Boilers and Auxiliary Equipment | Charlottetown | 1105 |
| Steam Turbine – Generators and Auxiliary Equipment | Charlottetown | 1107 |
| Gas Turbine – Generators and Auxiliary Equipment | Charlottetown | 1109 |
| Plant Electrical – Equipment | Charlottetown | 1113 |
| Power Plant – Miscellaneous Equipment | Charlottetown<br>Borden Plant<br>ECC | 1115<br>1215<br>1315 |
| Shop Tools and Equipment | | 1135 |
| River Pumphouse | | 1139 |
| Gas Turbine – Generators and Auxiliary Equipment | Borden | 1209 |
| Energy Control Centre | | 1379 |
| **TRANSMISSION AND DISTRIBUTION** | | |
| **Account Name** | **Section** | **Account Number** |
| Substation Land | Distribution<br>Transmission | 1740<br>1840 |
| Substation Equipment, Buildings and Structures | Distribution<br>Transmission | 1741<br>1841 |
| Road and Trails | Transmission | 1842 |
| Transmission and Distribution Land | Distribution<br>Transmission | 1744<br>1844 |
| Rights-of-Way Survey and Line Clearing Costs | Distribution<br>Transmission | 1746<br>1846 |
| Transmission Towers | Transmission | 1847 |
| Overhead Conductors | Distribution<br>Transmission | 1748<br>1848 |
| Poles and Fixtures | Distribution<br>Transmission | 1749<br>1849 |

| | | |
|---|---|---|
| Line Control Devices | Distribution<br>Transmission | 1750<br>1850 |
| Line Transformers | Distribution | 1751 |
| Line Transformer Installation | Distribution | 1752 |
| Service Lines | Distribution | 1753 |
| Street and Yard Lighting | Distribution | 1754 |
| Underground System Cables and Conduits | Distribution | 1755 |
| Underground System Service Lines | Distribution | 1756 |
| Underground System Street Lighting Supply | Distribution | 1757 |
| Meters | Distribution | 1758 |
| Meter Installation | Distribution | 1759 |
| Communication Equipment | | 1760 |
| Engineering, Test and Survey Equipment | | 1761 |
| Tools and Stores Equipment | Distribution | 1762 |
| Supervisory and Control Equipment (SCADA) | | 1763 |
| General Property - Land | Distribution | 1777 |
| General Property - Office Buildings and Structures | Distribution | 1778 |
| General Property - Line Buildings and Structures | Distribution | 1779 |
| Office Equipment | | 1780 |
| Transportation Equipment | | 1781 |
| Office Leasehold Improvements | | 1783 |
| **INFORMATION TECHNOLOGY** | | |
| **Account Name** | **Section** | **Account Number** |
| Computer Hardware | | 1784 |
| Computer Software | | 1785 |

| **CAPITAL PROJECT CODES AND UNDISTRIBUTED GENERAL EXPENSE CAPTIAL** | | |
|---|---|---|
| **Account Name** | **Section** | **Account Number** |
| Undistributed General Expense - Capital | General Expense Capital | 2000 |
| Capital Project Codes in Progress | | 2000 |
| ▪ Project Code Content | | |
| ▪ Initiating the Project Code | | |
| ▪ Closing Out the Project Code | | |

| RETIREMENT ACCOUNTING | | |
|---|---|---|
| **Account Name** | **Section** | **Account Number** |
| Accumulated Depreciation or Retirement Reserves | | |
| Withdrawals of Retirements | | |
| Salvage | | |

| CURRENT ASSETS | | |
|---|---|---|
| **Account Name** | **Section** | **Account Number** |
| Cash | | 3000 |
| Accounts Receivable | | 3100 |
| Materials and Supplies | | 3200-3299 |
| Repayments | | 3300-3399 |
| Other Current Assets | | 3400-3499 |
| Deferred Charges | | 3500-3599 |
| Rights-of-Way and Easements | | 3580 |
| Accumulated Amortization - Rights-of-Way and Easements | | 3582 |
| Internally Developed Software | | 3585 |
| Accumulated Amortization - Internally Developed Software | | 3586 |
| Long Term Investments | | 3600-3699 |
| Accounts Receivable Job Orders | | 3700-3999 |

| LIABILITIES AND SHAREHOLDER EQUITY | | |
|---|---|---|
| **Account Name** | **Section** | **Account Number** |
| Funded Debt | | 4000 |
| Payroll - Deductions and Overheads | | 4200-4299 |
| Accounts Payable | | 4300-4399 |
| Accrued Liabilities | | 4400-4499 |
| Contribution for Services | | 4500-4519 |
| Future Site Removal and Restoration | | 4520 |
| Future Income Tax | | 4600 |
| Shareholders' Equity | | 4700-4710 |
| Retained Earnings | | 4720 |

| INCOME AND SURPLUS ACCOUNTING | | |
|---|---|---|
| **Account Name** | **Section** | **Account Number** |
| Accumulated Amortization - General | | 5000 - 5028 |
| Retirement Project Codes in Progress | | 5100-5999 |

| OPERATING REVENUE ACCOUNTING | | |
|---|---|---|
| **Account Name** | **Section** | **Account Number** |
| Electric Revenue Accounts | | 6000-6400 |
| Other Revenues | | 6500-6599 |

| OPERATING EXPENSE ACCOUNTING | | |
|---|---|---|
| **Account Name** | **Section** | **Account Number** |
| Operating Expense | | 7000 -7499 |
| Power Purchases | | 7000 -7009 |
| Dalhousie | | 7010-7019 |
| Point Lepreau | | 7020-7039 |
| Other | | 7040-7099 |
| Charlottetown Steam Plant | | 7100-7199 |
| Borden Gas Turbine Generating Plant | | 7200-7299 |
| Charlottetown Thermal Generating Station CT | | 7300-7349 |
| Production - Other | | 7350-7399 |
| Maritime Interconnection Facilities - Government-Owned | | 7400-7499 |
| OATT | | 7500-7599 |

| GENERAL EXPENSE ACCOUNTING | | |
|---|---|---|
| **Account Name** | **Section** | **Account Number** |
| Transmission and Distribution - Other | | 7900-7999 |
| General Expense | | |

| OTHER INCOME DEDUCTIONS ACCOUNTING | | |
|---|---|---|
| **Account Name** | **Section** | **Account Number** |
| Other Income Deductions | | 9000-9999 |

**Numerical Order (refer to Account Number Diagram)**
The third segment or “natural” account code is key to ensuring assets and expenses are properly recorded. The four digit natural account is as follows:

1st digit – Account Type
2nd digit – Location Code
3rd and 4th digits – Activity Type

Situations can arise when an Account Code can cover more than on activity. In these situations, consistence and judgment are applied.

The Property, Plant and Equipment (PPE) Accounts of each distinct class of operations shall be subdivided into the main divisions, Production, Transmission, Distribution and General Property. Maritime Electric follows the guidelines for accounting established by the Federal Energy regulatory Commission's (FERC's) Uniform System of Accounts. The Account structure is a 4-segment, 13 digit series as follows:

| | | |
|---|---|---|
| First 2 digits | = | Department Code |
| Next 5 digits | = | Project Code |
| Next 4 digits | = | Natural Account Number |
| Last 2 digits | = | Expense Type |

CONSTRUCTION ACCOUNTS

When a large construction project is under consideration and study, preliminary legal and engineering expenses will be incurred, these expenses shall be carried in a Capital Project Code in Progress until such time as they can be allocated to the appropriate accounts in the classification of Fixed Capital Accounts in the second part of this section.

Before the construction work is started, the management, accountants and construction engineers should agree upon the accounting methods or systems to provide a detailed cost of the construction to be undertaken, and they shall prepare a classification of construction accounts or Project Codes which will permit the detailed cost of the construction to be easily condensed or reclassified.

Transmission includes one or more transmission lines or main transformers or substations interconnecting Production plants, and transmitting energy to substations supplying cities, towns, rural areas and large power customers. The Fixed Capital record for Transmission should show the total cost of Transmission segregated into units and if so directed by management each unit will be divided as prescribed in the classification for Transmission lines.

Distribution includes all land, structures, conversion equipment, lines, line transformers, and other facilities employed between the primary source of supply (i.e. generating station, or transmission system, or point of receipt in the case of purchased power) and of delivery of customers, which are not includible in transmission system, whether or not such land, structures, and facilities are operated as part of a transmission system or as part of a distribution system.

General Property includes property or equipment not assignable to Production, Distribution, or Transmission.

## PRODUCTION

**Production** consists of one or more power plants supplying electrical energy to an interconnected system serving various areas. The Fixed Capital record will show the total cost of each producing plant and, when so directed by the management each plant will be segregated into the classification prescribed for power plants.

### 1101/1201 POWER PLANT LAND

Includes the cost of land and land rights used in connection with steam-power, gas turbine or other internal combustion engine power generation. It shall not include the cost of buildings, structures or improvements other than as noted below.

Such items to be charged here include:

1. Survey in connection with acquisition of land.
2. Appraisals prior to closing title.
3. Examining and clearing title, insuring and registering in connection with the acquisition and defending against claims relating to the period prior to the acquisition.
4. Payments for obtaining consents or for abutting damages.
5. Conveyancers' and notaries' fees.
6. Fees, commissions and salaries to brokers, agents and others in connection with acquisition of the land.
7. Voiding leases upon purchase to secure possession of the land.
8. First cost of acquisition including mortgages and other liens assumed (but not subsequent interest thereon).
9. Filing satisfaction of mortgage.
10. Taxes accrued to the date of transfer of title.
11. Special assessments levied by public authorities for public improvements but <u>not</u> taxes levied to provide for maintenance of such improvements.
12. Grading the land except when directly occasioned by a building or structure.
13. Removing, relocating or reconstructing property of others, such as buildings, roads, power and communication lines, cemeteries, etc., in order to acquire quiet possession of land.
14. If on acquiring the land, buildings, structures or improvements are removed or wrecked without being used in the utility operation, the cost of removing or wrecking shall be charged to this account and any salvage credited to the account.

### 1102/1202 POWER PLANT - BUILDINGS AND STRUCTURES

Includes the cost of all permanent buildings, structures and improvements and all appurtenant fixtures devoted to the generation operation.

The cost of specially provided foundations not intended to outlast the machinery or apparatus for which provided, and the cost of steel work and castings, etc., installed to form part or all of a base of an item of equipment shall be charged to the same account as the cost of the machinery, apparatus or equipment.

The cost of weather protective enclosures forming part of, or supplied as an integral part of a gas turbine generating units shall be charged to the same account as the cost of the machinery, apparatus or equipment.

The cost of weather protective enclosures forming part of, or supplied as an integral part of a gas turbine generating unit shall be charged to the same account as the cost of the generating unit.

Some of the items to be included in the accounts for buildings and structures are as follows:

1. Architects and engineers plans and specifications including supervision.
2. Ash pits (when located with the building).
3. Boilers, furnaces, piping, wiring, fixtures and machinery for heating, lighting, signaling, ventilating, and air conditioning systems, plumbing, vacuum cleaning system, incinerator and smoke pipe, flues, etc.
4. Bulkheads, including dredging, riprap fill, piling decking, concrete, fenders, etc., when exposed and subject to maintenance and replacement.
5. Chimneys.
6. Coal bins and bunkers.
7. Commissions and fees to brokers, agents, architects and others.
8. Conduit (not to be removed) with its contents.
9. Damages to abutting property during construction.
10. Docks and wharves.
11. Door checks and door stops.
12. Drainage and sewerage systems.
13. Elevators, cranes, hoists, etc., and the machinery for operating them.
14. Excavation, including shoring, bracing, bridging, refill, and disposal of excess excavated material, cofferdams around foundation, pumping water from cofferdam during construction, and test borings.
15. Fences and fence curbs (not including protective fences isolating items of equipment, which shall be charged to the appropriate equipment account).
16. Fire protection systems when forming a part of a structure.
17. Floor covering (permanently attached).
18. Foundations and piers for machinery, constructed as a permanent part of a building or other item listed herein.
19. Grading and clearing when directly occasioned by the building of a structure.
20. Intrasite communication system, pole, pole fixtures, wires and cables.
21. Landscaping, lawns, shrubbery, etc.
22. Leases, voiding upon purchase, to secure possession of structures.
23. Leased property, expenditures on.
24. Lighting fixtures and outside lighting system.
25. Initial painting.
26. Permanent paving, concrete, brick, flagstone, asphalt, etc., within the property lines.
27. Partitions, including movable.
28. Permits and privileges.
29. Platforms, railings and gratings when constructed as part of a structure.
30. Power boards for services to a building.
31. Refrigerating systems for general use.
32. Retaining walls except when identified with land.
33. Roadways, railroads, bridges, and trestles intrasite except railroads provided for in equipment accounts.
34. Roofs.
35. Scales, connected to and forming a part of a structure.
36. Screens.
37. Sidewalks, culverts, curbs and streets constructed by the utility on its property.

38. Sprinkling systems.
39. Sump pumps and pits.
40. Stacks - brick, steel, concrete or fiberglass, when set on foundation forming part of general foundation and steelwork of a building.
41. Steel inspection during construction.
42. Storage facilities constituting a part of a building.
43. Storm doors and windows.
44. Subways, areaways, and tunnels, directly connected to and forming part of a structure.
45. Tanks, constructed as part of a building or as a distinct structural unit.
46. Temporary heating during construction (net cost).
47. Temporary water connection during construction (net cost).
48. Temporary shanties and other facilities used during the construction (net cost).
49. Topographical maps.
50. Water front improvements.
51. Water meters and supply system for a building or for general company purposes.
52. Water supply piping, hydrants and wells.
53. Window shades and ventilators.
54. Yard drainage system.
55. Yard lighting system.
56. Yard surfacing, gravel, concrete, or oil (first cost only).

### 1103 PUMPHOUSE – MECHANICAL EQUIPMENT

Includes the cost installed of mechanical equipment located in a pumphouse, used for the purpose of supplying circulating water for condensing and cooling purposes, the pumphouse being remote from the plant building housing the generating machinery.

The cost of circulating water pumps, including motors, suction and discharge, valves and valve operators, water screens, screen wash pump, screen wash piping, valves and filters, and other mechanical equipment used in conjunction with this, and their installation are charged to this account.

### 1104 PUMPHOUSE – ELECTRICAL EQUIPMENT

Includes the cost of electrical equipment associated with the pumphouse which is remote from the plant and supplying circulating water to the plant for condensing and cooling purposes.

Includes the cost of overhead and underground power supply circuits, transformers, switchgear, cables, conduits, motor protection and control devices and the installation of this equipment. It does not include the main primary supply circuit breakers which are normally located in the plant.

### 1105 STEAM BOILERS AND AUXILIARY EQUIPMENT

Includes the cost installed of furnaces, boilers, and boiler apparatus and accessories, devoted to the production of steam for electric generation and for steam sales.

The specific items are:

1. Ash handling equipment, including hoppers, gates, cars, conveyors, hoists, sluicing equipment, including pumps and motors, sluicing water pipe and fittings, sluicing trenches and accessories, etc., except sluices which are a part of a building.

2. Boiler feed system, including feed water heaters, evaporator condensers, heater drain pumps, heater drainers, de-aerators, and vent condensers, boiler feed pumps, surge tanks, feed water regulators, feed water measuring equipment, and all associated drives.
3. Boiler plant cranes and hoists and associated drives.
4. Boilers and equipment, including boilers and baffles, economizers, superheaters, soot blowers, foundation and settings, water walls, arches, grates, insulation, slowdown system, drying out of new boilers, also associated motors or other power equipment.
5. Breeching and accessories, including breeching, dampers, soot spouts, hoppers and gates, cinder eliminators, breeching insulation, soot blowers and associated motors.
6. Coal handling and storage equipment, including coal towers, coal lorries, coal cars, locomotives and tracks when devoted principally to the transportation of coal, hoppers downtakes, unloading and hoisting equipment, skip hoists and conveyors, weighting equipment, magnetic separators, cable ways, housings and supports for coal handling equipment.
7. Draft equipment, including air preheaters and accessories induced and forced draft fans, air ducts, combustion control mechanisms, and associated motors or other power equipment.
8. Gas-burning equipment including holders, burner equipment and piping, control equipment, etc.
9. Instruments and devices, including all measuring, indicating and recording equipment for boiler plant services together with mounting and supports.
10. Lighting systems.
11. Oil-burning equipment, including tanks, heaters, pumps with drive burner equipment and piping, control equipment, etc.
12. Pulverized fuel equipment, including pulverizers, necessary motors, primary air fans, cyclones and ducts, dryers, pulverized fuel bins, pulverized fuel conveyors, and equipment, burners, burner piping priming equipment, air compressors, motors, etc.
13. Stacks, including foundations and supports, stack steel and ladders, stack brick work, stack concrete, stack lining, stack painting (first), when set on separate foundation independent of substructure or superstructure of building.
14. Station piping, including pipe, valves, fittings, separators, traps, desuperheaters, hangars, excavation, covering, etc., for station piping system, including all steam, condensate, boiler feed and water supply piping, etc., but not condensing water, plumbing, building heating, oil, gas, air piping.
15. Stoker or equivalent feeding equipment, including stokers and accessory motors, clinker grinders, fans and motors, etc.
16. Ventilating equipment.
17. Water purification equipment, including softeners, demineralizers and accessories, evaporators and accessories, heat exchangers, filters, tanks for filtered or softened water, pumps, motors, etc.
18. Water-supply systems, including pumps, motors, strainers, raw-water storage tanks, boiler wash pumps, intake and discharge pipes and tunnels not a part of a building.

### 1107 STEAM TURBINE – GENERATORS AND AUXILIARY EQUIPMENT

Includes the cost installed of main turbine-driven units and accessory equipment used in generating electricity by steam.

The specific items are:

1. Air cleaning and cooling apparatus, including blowers, drive equipment, air ducts not a part of building, louvers, pumps, hoods, etc.
2. Circulating pumps, including connections between condensers and intake and discharge wells and tunnels.
3. Condensers, including condensate pumps, air and vacuum pumps, ejectors, unloading valves and vacuum breakers, expansion devices, screens, etc.
4. Generator hydrogen gas piping system and hydrogen detrainment equipment.
5. Cooling system, including towers, pumps, tanks, and piping.
6. Cranes, hoists, etc., including items wholly identified with items listed herein.
7. Excitation system, when identified with main generating units.
8. Fire-extinguishing systems.
9. Foundations and settings, especially constructed for and not expected to outlast the apparatus for which provided.
10. Governors.
11. Lighting systems.
12. Lubricating systems, including gauges, filters, water separators, tanks, pumps, piping, motors, etc.
13. Mechanical meters, including gauges, recording instruments, sampling and testing equipment.
14. Piping-main exhaust, including connections between turbo-generator and condenser and between condenser and hot-well.
15. Piping-main steam, including connections from main throttle valve to turbine inlet.
16. Platforms, railings, steps, gratings, etc., appurtenant to apparatus listed herein.
17. Pressure oil systems, including accumulators, pumps, piping, motors, etc.
18. Steelwork, specially constructed for apparatus listed herein.
19. Throttle and inlet valve.
20. Tunnels, intake and discharge, for condenser system, when not a part of a structure, water screens, etc.
21. Turbo-generators-main, including turbine generator, field rheostats and electric connections for self-excited units.
22. Water screens, motors, etc.
23. Moisture separators for turbine steam.
24. Turbine lubricating oil (initial charge).

### 1109 GAS TURBINE – GENERATORS AND AUXILIARY EQUIPMENT

This account shall include the cost installed of main turbine-driven units and accessory equipment used in generating electricity by steam.

The specific items are:

1. Air cleaning and cooling apparatus including blowers, drive equipment, air ducts not a part of building, louvers, pumps, hoods, etc.
2. Circulating pumps, including connections between condensers and intake and discharge tunnels.
3. Condensers, including condensate pumps, air and vacuum pumps, ejectors, unloading valves and vacuum breakers, expansion devices, screens, etc.
4. Generator hydrogen, gas piping and detrainment equipment.
5. Cooling system, including towers, pumps, tanks, and piping.
6. Cranes, hoists, etc., including items wholly identified with items listed herein.
7. Excitation system, when identified with main generating units.

8. Fire-extinguishing systems.
9. Foundations and settings especially constructed for and not expected to outlast the apparatus for which provided.
10. Governors.
11. Lighting systems.
12. Lubricating systems, including gauges, filters, water separators, tanks, pumps, piping, motors, etc.
13. Mechanical meters, including gauges, recording instruments, sampling and testing equipment.
14. Piping - main exhaust, including connections between turbogenerator and condenser and between condenser and hotwell.
15. Piping - main steam including connections from main throttle valve to turbine inlet.
16. Platforms, railings, steps, gratings, etc., appurtenant to apparatus listed herein.
17. Pressure oil systems including accumulators, pumps, piping, motors, etc.
18. Steelwork, specially constructed for apparatus listed herein.
19. Throttle and inlet valve.
20. Tunnels, intake and discharge, for condenser system, when not a part of structure, water screens, etc.
21. Turbogenerators - main, including turbine and generator, field rheostats and electric connections for self-excited units.
22. Water screens, motors, etc.
23. Moisture separator for turbine steam.
24. Turbine lubricating oil (initial charge).

### 1113 PLANT ELECTRICAL - EQUIPMENT

Includes the cost installed of auxiliary generating apparatus, conversion equipment and equipment used primarily in connection with the control and switching of electric energy produced by generating equipment, and the protection of electric circuits and equipment. It does not include transformers and other equipment used for changing the voltage and frequencies of electricity for transmission or distribution.
The specific items are:

1. Auxiliary generators, including boards, compartments, switchgear and equipment, and connections to auxiliary power bus.
2. Exciters when driven separately from the main primemover, including its drive, rheostats, storage batteries and charging equipment, circuit breakers, panels and accessories, knife switches and accessories, surge arrestors, instrument shunts, conductors and conduit, special supports for conduit, generator field and exciter switch panels, exciter bus tie panels, generator and exciter rheostats, etc., special housing, protective screens, etc.
3. Generator main connections, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, current transformers, potential transformers, protective relays, isolated panels and equipment, conductors, and conduit, special supports for generator main leads, grounding switch, etc., special housing, protective screens, etc.
4. Station buses including main, auxiliary, transfer, synchronizing and fault ground buses, including circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, reactors and accessories, voltage regulators and accessories, compensators, resistors, starting transformers, current transformers, potential transformers, protective relays, storage batteries and charging equipment,

isolated panels and equipment, conductors and conduit, special supports, special housings.
5. Concrete pads, general station grounding system, special fire-extinguishing system, and test equipment.
6. Station control system, including station switchboards with panel wiring, panels with instruments and control equipment only, panels with switching equipment mounted or mechanically connected, trucktype boards complete, cubicles, station supervisory control boards, generator and exciter signal stands, temperature recording devices, frequency-control equipment, master clocks, watt-hour meters and synchronoscope in the turbine room, station totalizing watt-meter, boiler-room load indicator equipment, storage batteries, panels and charging sets, instrument transformers for supervisor metering, conductors and conduit, special protective screens, doors, etc.

**NOTE:** When any item of equipment listed herein is used wholly to furnish power to equipment included in another account, its cost shall be included in such other account.

## 1115/1215/1315 POWER PLANT – MISCELLANEOUS EQUIPMENT

This account shall include the cost installed of miscellaneous equipment in and about the generating plants devoted to general station use and which is not included in foregoing accounts concerning power production accounts.

The specific items include:

1. Compressed air and vacuum cleaning systems, including tanks, compressors, exhausters, air filters, piping, etc.
2. Mobile cranes and hoisting equipment, including crane cars, crane rails, monorails, hoists, etc.
3. Fire extinguishing equipment for general station use.
4. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided.
5. Locomotive cranes not includible elsewhere.
6. Locomotives not includible elsewhere.
7. Marine equipment, including boats, barges, etc.
8. Miscellaneous belts, pulleys, countershafts, etc.
9. Miscellaneous equipment, including atmospheric and weather-indicating devices, intrasite communication equipment, laboratory equipment, signal systems, callophones, emergency whistles and sirens, fire alarms, insect-control equipment and other similar equipment.
10. Railway cars not includible elsewhere.
11. Refrigerating systems, including compressors, pumps, cooling coils, etc.
12. Station maintenance equipment, including lathes, shapers, planers, drill presses, hydraulic presses, grinders, etc., with motors, shafting, hangars, pulleys, etc.
13. Ventilating equipment, including items wholly identified with apparatus listed herein.

## 1135 SHOP TOOLS AND EQUIPMENT

This account shall include the cost of tools, implements and equipment used in the Production area in repair work and general plant shops. It also includes the cost of equipment for receiving, shipping, handling and storage of production materials and supplies such as hoists, lockers, scales, shelving, storage bins, hand trucks, wheelbarrows, machine tools, motor-driven tools, tool racks, vises, work benches, etc.

### 1139 RIVER PUMPHOUSE

Includes the cost of all permanent buildings, structures and improvements and all appurtenant fixtures devoted to the river pumphouse operation.

The cost of specially provided foundations not intended to outlast the machinery or apparatus for which provided, and the cost of steel work and castings, etc., installed to form part or all of a base of an item of equipment shall be charged to the same account as the cost of the machinery, apparatus or equipment.

Some of the items to be included in the accounts for buildings and structures are as follows:

1. Architects and engineers plans and specifications including supervision.
2. Piping, wiring, fixtures and machinery for heating, lighting, signaling, ventilating, and air conditioning systems, plumbing, vacuum cleaning system.
3. Bulkheads, including dredging, riprap fill, piling, decking, concrete, fenders, etc., when exposed and subject to maintenance and replacement.
4. Commissions and fees to brokers, agents, architects and others.
5. Conduit (not to be removed) with its contents.
6. Damages to abutting property during construction.
7. Docks and wharves.
8. Door checks and door stops.
9. Drainage and sewerage systems.
10. Elevators, cranes, hoists, etc., and the machinery for operating them.
11. Excavation, including shoring, bracing, bridging, refill, and disposal of excess excavated material, cofferdams around foundation, pumping water from cofferdam during construction, and test borings.
12. Fences and fence curbs (not including protective fences isolating items of equipment, which shall be charged to the appropriate equipment account).
13. Fire protection systems when forming a part of a structure.
14. Floor covering (permanently attached).
15. Foundations and piers for machinery, constructed as a permanent part of a building or other item listed herein.
16. Grading and clearing when directly occasioned by the building of a structure.
17. Intrasite communication system, poles, pole fixtures, wires and cables.
18. Landscaping, lawns, shrubbery, etc.
19. Leases, voiding upon purchase, to secure possession of structures.
20. Leased property, expenditures on.
21. Lighting fixtures and outside lighting system.
22. Initial painting.
23. Permanent paving, concrete, brick, flagstone, asphalt, etc., within the property lines.
24. Partitions, including movable.
25. Permits and privileges.
26. Platforms, railings and gratings when constructed as a part of a structure.
27. Power boards for services to a building.
28. Refrigerating systems for general use.

29. Retaining walls except when identified with land.
30. Roadways, railroads, bridges, and trestles intrasite except railroads provided for in equipment accounts.
31. Roofs.
32. Scales, connected to and forming a part of a structure.
33. Screens.
34. Sidewalks, culverts, curbs and streets constructed by the utility on its property.
35. Sprinkling systems.
36. Sump pumps and pits.
37. Stacks - brick, steel, concrete or fiberglass, when set on foundation forming part of general foundation and steelwork of a building.
38. Steel inspection during construction.
39. Storage facilities constituting a part of a building.
40. Storm doors and windows.
41. Subways, areaways, and tunnels, directly connected to and forming part of a structure.
42. Tanks, constructed as part of a building or as a distinct structural unit.
43. Temporary heating during construction (net cost).
44. Temporary water connection during construction (net cost).
45. Temporary shanties and other facilities used during the construction (net cost).
46. Topographical maps.
47. Tunnels, intake and discharge, when constructed as part of a structure, including sluice gates, and those constructed to house mains.
48. Vaults, constructed as part of building.
49. Water basins or reservoirs.

## 1209 GAS TURBINE – GENERATORS AND AUXILIARY EQUIPMENT - BORDEN

Includes the costs installed of gas turbine-driven units and accessory equipment used in generating electricity.

The specific items are:

1. Air cleaning and cooling apparatus, including blowers, fans, drive equipment, air ducts, louvers, pumps, hoods, etc.
2. Controls, including fuel controls, governoring equipment, excitation controls, batteries, voltage regulators, and all instrumentation necessary for automatic and manual operation of the unit.
3. Compressors, air receivers, filters, etc.
4. Generator hydrogen gas piping system and hydrogen detrainment equipment.
5. Cooling systems including pumps, tanks, and piping.
6. Cranes, hoists and trolleys associated with the equipment listed herein.
7. Excitation system.
8. Fire extinguishing systems.
9. Foundations and settings, specially constructed for and not expected to outlast the apparatus for which provided.
10. Governors.
11. Lighting systems.

12. Lubricating systems, including gauges, filters, water separator, tanks, pumps, piping, motors, etc.
13. Mechanical meters, including gauges, recording instruments, sampling and testing equipment.
14. Platforms, railings, steps, gratings, etc., appurtenant to apparatus listed herein.
15. Pressure oil systems, including accumulators, pumps, piping, motors, etc.
16. Steelwork, specially constructed for apparatus listed herein.
17. Turbine, including gas generator, power turbine, reduction gearing, couplings, generators, field rheostats and electric connections.
18. Housings supplied with and forming part of the unit, including turbine and generator weatherproof housing, control and switchgear housing.
19. Ducts, including air inlet and exhaust ducts, filters and silencing baffles.
20. Fences installed specifically for equipment concerned.
21. Lubricating oil, first fill.
22. Fuel system including pumps, piping, tanks, filters, etc., installed for the specific unit; fuel used for commissioning.
23. Electrical equipment up to and including the generator circuit breaker, including cables, conduits, instrument transformer control panels, circuit breakers, surge diverters, capacitors, grounding transformers, resistors and reactors, space heating system, unit auxiliary transformer, inverters, battery chargers, auxiliary panels and wiring, etc.

### 1379 ENERGY CONTROL CENTRE

This account includes the cost of the building in which the Energy Control Center is located. It also includes the cost of all fixtures permanently attached to and made a part of the building and which cannot be removed without impairment to the building, as well as the cost of improvements of a permanent character.

## TRANSMISSION AND DISTRIBUTION

### 1740/1840 SUBSTATION LAND

Includes the cost of all land devoted to distribution or transmission substations or switching operations outside of a generating plant property or land acquired solely for electric power generating purposes. It shall not include the cost of buildings, structures or improvements (other than public improvements noted in item (11) below).

The account shall include, when cost is assumed or paid by the Company, on its own behalf, the cost of:

1. Survey in connection with acquisition of the land.
2. Appraisals prior to closing title.
3. Examining and clearing title, insuring and registering the title in connection with the acquisition and defending against claims relating to the period prior to the acquisition.
4. Payments for obtaining consents or for abutting damages.
5. Conveyancers' and notaries' fees.
6. Fees, commissions and salaries to brokers, agents and others in connection with acquisition of the land.
7. Voiding leases upon purchase to secure possession of the land.

8. First cost of acquisition including mortgages and other liens assumed (but not subsequent interest thereon).
9. Filing satisfaction of mortgage.
10. Taxes accrued to the date of transfer to title.
11. Special assessments levied by public authorities for public improvements but not taxes levied to provide for the maintenance of such improvements.
12. Grading the land except when directly occasioned by a building or structure.
13. Removing, relocating or reconstructing property of others, such as buildings, roads, power and communication lines, cemeteries, etc., in order to acquire quiet possession of the land.
14. If on acquiring the land, buildings, structures or improvements are removed or wrecked without being used in the utility operations, the cost of removing or wrecking shall be charged to this account and any salvage credited to the account.

## 1741/1841 SUBSTATION EQUIPMENT, BUILDINGS AND STRUCTURES

This account shall include the cost in place of all permanent buildings, structures, facilities and improvements to house, safeguard or support apparatus and equipment devoted to distribution or transmission substation or switching operations outside of a generating plant property or land acquired solely for electric power generating purposes.

Improvements include such items as roadways, fences, sidewalks, sewer and water systems, yard lighting, grading and landscape gardening, monuments and other permanent structures.

The account shall also include the installed cost of all distribution or transmission substation equipment including specially provided foundations. It will include such items as power transformers, converters, motor generators, regulators, switchgear, switching apparatus, etc., used primarily for changing electric power in either frequency of voltage or in controlling and measuring power and energy into or out of the distribution or transmission systems.

It will also include transformers installed in a distribution or transmission line to transform the voltage at a point between distribution or transmission systems of different operating voltage.

This account does not include distribution line transformers installed to step down the voltage from the utility's distribution system to the voltage at which it is used by the customer (normally 600 volts or less).

## 1842 ROAD AND TRAILS

Charge to this account the cost of roads, trails, bridges used primarily as transmission facilities.

The specific items are:

1. Bridges including foundation piers, girders, trusses, flooring, etc.
2. Clearing land.
3. Roads including grading, surfacing, culverts, etc.
4. Structures constructed and maintained in connection with items included herein.
5. Trails including grading, surfacing, culverts, etc.

NOTE: The cost of temporary roads, bridges, etc., necessary during the period of construction but abandoned or dedicated to public use upon completion of the plant, shall be charged to the accounts appropriate for the construction.

**1744/1844 TRANSMISSION AND DISTRIBUTION LAND**

Charge to this account the cost of all land acquired and used primarily for the distribution or transmission of power and energy from one point to another outside of substation or generating plant land, including examination, searching and clearing title and registration of title, and other similar assignable costs as noted under "Substation Land" account (see 1740 and 1840).

**1746/1846 RIGHTS-OF-WAY SURVEY AND LINE CLEARING COSTS**

This account shall include the cost of line survey and initial or original clearing of trees and vegetation in right of way and for the construction of distribution or transmission lines.

The cost of the survey work related to land clearing, erection of poles and fixtures, the cost of initial land clearing are initially charged to 2746 or 2846 in the capital work order process. At year-end, the balances in these accounts will be transferred to the XX49 (poles) or 2753 (services) account in the Property Plant and Equipment categories.

This treatment is in order to track the costs of tree clearing and vegetation management associated with the new line construction and extensions and certain line rebuilds.

**1847 TRANSMISSION TOWERS**

This account includes the installed cost of tower and associated fixtures used for supporting overhead transmission conductors, including:

1. Anchors, guys and braces
2. Brackets
3. Crossarms
4. Excavation, backfill and disposal of excavated material
5. Foundation
6. Guards
7. Insulator pins and suspension bolts
8. Ladders and steps
9. Railings
10. Towers
11. Warning lights

**1748/1848 OVERHEAD CONDUCTORS**

Includes the cost of all overhead conductors used for the distribution or transmission of power and energy from one point to another, excluding service lines. It will cover all cables, conductors, and insulators installed above ground on towers or pole structures located outside of substation or generating plant structures.

**1749/1849 POLES AND FIXTURES**

This account shall include the cost installed of distribution or transmission line poles of wood or other material together with appurtenant fixtures used for supporting the overhead conductors but excluding line support insulators. It includes the cost of pole structure, transformer platforms and supporting poles, and structures supporting other line devices, crossarms, insulator pins, braces, brackets, guys and other supports for holding the structures in position. It does not include any structures erected for substation or generating plant purposes.

### 1750/1850 LINE CONTROL DEVICES
This account will include the cost installed of major electrical apparatus and devices installed on distribution or transmission line structures for the automatic control, protection or electrical measurement of these lines. It will include such devices as voltage regulators, reclosers, capacitor banks, non-revenue metering outfits, air breaks, automatic sectionalizing switches, etc., located outside of substation or generating plant structures.

### 1751 LINE TRANSFORMERS
This account shall include the landed purchase cost of overhead, padmounted, submersible, and vault-type distribution line transformers owned by the utility for use in transforming electricity to the voltage at which it is supplied and used by the customer whether or not such units are in service or held in stock. It will also include the cost of lightning arrestors if used in conjunction with the transformer, fuse cut-outs, housings, foundations, enclosures and all material used solely for the installation of the transformer but excluding transformer platforms and supporting poles.

When a transformer is permanently retired from service, the original cost thereof shall be credited to this account.

The records covering line transformers shall be kept that the utility can furnish the number of transformers of various capacities in service and those in reserve, and the location and the use of each transformer.

### 1752 LINE TRANSFORMER INSTALLATION
Charge to this account all labour, transportation and incidental expenses for the initial installation of any new transformer. This account will not include the cost of setting or removing an existing transformer relocated from one installation point to another.

### 1753 SERVICES LINES
Includes the cost installed of all overhead conductors, conduits, insulators, racks, clamps, ducts, supports, etc., leading from the last pole of the overhead distribution system to the point of connection with the customer's outlet or entrance installation.

### 1754 STREET AND YARD LIGHTING
Charge to this account the cost installed of all lamp posts, lighting fixtures and control devices operated and maintained for street, highway, yard and area lighting under contract entered into with a municipality, village or individuals. It will include street lighting transformers and equipment installed above ground, supports, suspension and control devices, overhead conduits, cables and conductors, if used exclusively for lighting service. The first installation of lamp bulbs should be charged to this account. This account does not include area lighting equipment installed on substation or generating plant property.

### 1755 UNDERGROUND SYSTEM CABLES AND CONDUITS
This account shall include the installed cost of all conduits, manholes, pullpits, duct banks, sewer connections, sewer traps and all material and apparatus necessary for the construction of a duct bank system to house underground cables and line control devices.

It shall also include the installed cost of all power cables, neutral wires, ground wires, grounding systems, terminators, splices, and lighting arrestors used in conjunction with primary and secondary distribution systems and all pole-mounted equipment necessary to facilitate the attachment of underground cables to the poles.

This account shall include the installed cost of all underground fusing, switching, sectionalizing, whether manual or automatic used in conjunction with an underground distribution system.

### 1756 UNDERGROUND SYSTEM SERVICE LINES

This account shall include the installed cost of all underground service cables, connectors, conduits, ducts, supports, etc., leading from the last pole of the overhead system, from the terminals of the transformer, or from a distribution bus system to the customer entrance installation.

### 1757 UNDERGROUND SYSTEM STREET LIGHTING SUPPLY

This account shall include the installed cost of all lamp posts, bases, lighting fixtures, control devices, fuses, fittings, underground conduits, cable and connectors used in conjunction with street and yard lighting where lighting supply originates underground.

### 1758 METERS

This account shall include the landed purchase cost of new meters, metering devices and appurtenances used in measuring power or energy delivered to a customer whether such equipment is actually in service or held in stock. It will also include the cost of the first Company and Government tests of the meter.

When a meter is permanently retired from service, the original cost thereof shall be credited to this account.

The records covering meters shall be so kept that the utility can provide information as to the number of meters of various capacities in service and in reserve as well as the location of each meter owned.

This account shall not include meters for recording output of a generating station, substation meters, etc. It includes only those meters used to record energy delivered to customers.

### 1759 METER INSTALLATION

Charge to this account the cost of initial installation of a new meter or metering device used for determination or measurement of power and energy delivered to a customer. It will not include the cost of setting or removing an existing meter relocated from one installation point to another.

### 1760 COMMUNICATION EQUIPMENT

Includes the cost installed of radio receivers, transmitters, terminal equipment, antenna, towers, associated motor generator sets, battery chargers and associated apparatus together with structures and improvements used exclusively for the purpose of operating a private radio communication system within the company. It will also include an overhead or underground multiplex, telephone lines and fibre-optic lines erected and operated by the utility as a component part of the system.

### 1761 ENGINEERING, TEST AND SURVEY EQUIPMENT
This account shall include the cost installed of engineering and laboratory equipment used for testing, measurement, laboratory and engineering purposes not specifically provided for or includible in other functional accounts. It will include such items as transits, levels, ammeters, voltmeters, rotating standards, testing panels, portable ammeters, voltmeters and watt meters, variacs, galvanometers, etc.

### 1762 DISTRIBUTION TOOLS AND STORES EQUIPMENT
This account shall include the cost of tools, implements and equipment used in repair work, general shops, line construction and garages, excluding generating plant shop tools and equipment. It also includes the cost of equipment for receiving, shipping, handling and storage of line materials and supplies such as chain falls, counters, cranes, hoists, lockers, scales, shelving, storage bins, hand trucks, wheelbarrows, etc.

### 1763 SUPERVISORY AND CONTROL EQUIPMENT (SCADA)
Includes the cost installed of supervisory, telemetering and remote controlled equipment both master units and remote terminal units, dedicated computers, terminal facilities, keyboards, screens, printers and associated equipment.

### 1777 GENERAL PROPERTY - LAND
Charge to this account the cost of all land acquired not assignable to any other account in this classification (i.e. plant, substation, T. & D.) Such costs include cost of survey, examination of title, registration of title fees, and other costs similar to those noted for "Substation Land".

### 1778 GENERAL PROPERTY – OFFICE BUILDINGS AND STRUCTURES
Charge to this account the cost of buildings, structures and improvements not assignable to any other buildings and structures account.

### 1179 GENERAL PROPERTY – LINE BUILDINGS AND STRUCTURES
Charge to this account the cost of buildings, structures, and improvements used in line operations and not assignable to any other buildings and structures account.

### 1780 OFFICE EQUIPMENT
This account shall include the cost of office furniture and equipment devoted to utility service and not permanently attached to buildings, such as desks, chairs, tables, moveable safes, filing cabinets, drafting tables, adding machines, billing and accounting machines, computers and photocopiers, etc. Small articles of slight value or short life should not be charged to this account but to the appropriate operating expense account.

### 1781 TRANSPORTATION EQUIPMENT
Includes the cost of equipment for general transportation purposes such as aircraft, automobiles, motor trucks, bicycles, snowmobiles, motor cycles, tractors, trailers and associated equipment such as battery chargers, gasoline and oil storage tanks and pumps. It will also include line construction digging equipment, winches, line bodies, aerial buckets and ladders, etc., which are mounted or attached as an integral part of the vehicle.

### 1783 OFFICE LEASEHOLD IMPROVEMENTS
The cost of substantial initial improvements (including repairs, rearrangements, additions, and betterments) made in the course of preparing for utility service property leased for a period of more than one year, and the cost of subsequent substantial additions, replacements, or

betterments to such property, shall be charged to the utility plant account appropriate for the class of property leased. If the service life of the improvements is terminable by action of the lease, the cost, less net salvage, of the improvements shall be spread over the life of the lease. However, if the service life is not terminated by action of the lease but by depreciation proper, the cost of the improvements, less net salvage, shall be accounted for as depreciable plant.

If improvements made to property leased for a period of more than one year are of relatively minor cost, or if the lease is for a period of not more than one year, the cost of the improvements shall be charged to the account in which the rent is included either directly or by amortization thereof.

## INFORMATION TECHNOLOGY

### 1784 COMPUTER HARDWARE
This account shall include the cost of general-purpose computer hardware.

### 1785 COMPUTER SOFTWARE
This account shall include the cost of systems software and a right or license to use computer software.

## 2000 UNDISTRIBUTED GENERAL EXPENSE - CAPITAL

This account accumulates charges of a capital-related nature which are not readily assignable to any particular capital account number/Project Code.

At year-end, the accumulated costs are re-allocated to fixed assets on a predetermined proportionate allocation.

## 2000 CAPITAL PROJECT CODES IN PROGRESS

Project Code Content

Every Project Code must contain the following information: name and number of project; location of project; department or division having custodial responsibility; budget item number (this may be the same as the project number;) description of work to be performed; reason for work (justification); account numbers involved; and an estimate of costs, quantities, and description of materials and labor needed. The Project Code also must include a cost summary detailing direct costs (labor, materials and supplies, contract costs, and transportation); overheads (including construction, supervision, engineering, and administrative items); interest charged to construction; and customer contributions in aid of construction. Finally, the order must show the date and name of person(s) preparing the Project Code and the date and name of person(s) approving the Project Code. Any maps, engineering drawings, or other diagrams to be used by construction personnel should be attached to the order.

Initiating the Project Code

The Project Code in its initial stages is a mechanism for alerting those departments or individuals involved in the project. The drawings, for example, would have to be prepared by the engineering department, which, if the work is being done internally, would generate bills of material to be used in the actual performance of the job. The Project Code, through the engineering department, then would trigger action by the stores department to make the proper materials available. If they are not in stock, the purchasing department would have to be notified to order the required items. If the job were to be performed by an outside contractor, the purchasing department would have received the original Project Code and would have been asked to solicit bids for the work from outside vendors.

Closing Out the Project Code

As construction progresses, the Project Code will accumulate information relative to new materials and supplies used. This basic data is needed by the capital records accounting section in order to make proper entries in the temporary work in progress accounts. In the cost accounting analysis prior to the distribution of work in progress to permanent asset accounts, overhead items - including construction, supervision, engineering, and administrative costs, and interest during construction - and, where appropriate, tool expense should be accounted for.

Upon completion of the particular project or subtotaling of a blanket or standing Project Code, the accountant will analyze and distribute from the work in progress accounts to the appropriate plant accounts and update the continuing property records at year-end. Otherwise, incomplete Project Codes are carried forward to the subsequent year as carryovers. A comparison also must be made between the estimated and actual costs with the proper explanation of variances which, in turn, serve as a check between budgeted and actual expenditures.

These instructions apply to both construction and retirement Project Codes. With retirement Project Codes, additional costs recorded will be costs of removal (including overheads) and salvage values, as well as the original costs of the assets retired.

This range of accounts is subdivided to identify the classifications complementary to the fixed asset accounts.

| | |
|---|---|
| 2000 | General Expense - Capital |
| 21XX | Plant |
| 27XX | Distribution |
| 28XX | Transmission |

The last two digits of the account number identifies the fixed asset to which the capital Project Code relates.

Each Project Code is coded with a suffix five-digit number to account separately for that particular Project Code.

By Retirement Accounting as treated under this heading is meant the accounting procedure to be followed in setting up Depreciation or Retirement Reserves; the removal from Fixed Capital accounts of property retired or abandoned; the procedure in recording the expenditures for retiring and replacing property; in determining the charges to made to the Depreciation or Retirement Reserves for property retired or abandoned; and the treating of salvage.

<u>Accumulated Depreciation or Retirement Reserves</u>
This account shall be credited with such amounts as are charged to Operating Expenses, appropriated from Retained Earnings, or both, as directed by management, to cover the value plus cost of dismantling less the salvage value of fixed capital retired from service.

<u>Withdrawals of Retirements</u>
To the end that the capital accounts shall at all times disclose the cost of property, the book value of retired property, whether replaced or not, must be deducted from (i.e. credited to) the account or accounts in this classification to which such cost was charged. When anything is worn out lost, sold, destroyed, abandoned, surrendered upon lapse of title, becomes permanently unserviceable, or is withdrawn or retired from service for any other reason, the amount at which such property stood charged in the capital account shall be credited to the appropriate capital account.

If the particular value is not separately recorded, it shall be taken to be the proportionate share of the said property recorded for the entire group in which the property is included, or if there is no record, the value of the property shall be estimated by the company engineers, and the recording entry of withdrawal shall state the fact of such estimation. Credits to Capital Account for property retired shall include such part of Capital General Expense as is equitably assignable to the item retired.

The value of any item retired, together with the cost of dismantling or removing from service, less any credits for salvage shall be charged to the Depreciation or Retirement Reserve.

The foregoing instructions do not apply to the retirement of minor parts, for which the charges are made directly to Operating expense accounts as directed by management.

<u>Replacements Chargeable to Fixed Capital Accounts</u>
Replacement expenditures shall include the cost of all labour, material and other expenses incurred in replacement of property that has been retired from service, and such expenditures shall be treated in a manner similar to those for new Capital Additions.

<u>Salvage</u>
Salvage, as termed in Retirement Accounting, means the value to the company of equipment or other material recovered in the process of dealing with withdrawals or retirement of property, which may be the amount realized from the sale of the equipment, or the estimated value to the company (if the nature of the equipment or material is similar to general stores stock normally used in the operations of the company).

Equipment or materials which are not sold, and cannot be used by the company, shall not be considered as salvage until disposed of.

(See also 2000 - 2999 Project Code System)

Current assets are cash, those assets readily convertible to cash, or are held for current use in operations or construction, current claims against others, payment of which is reasonably assured, and amounts accruing to the utility which are subject to current settlement, except such items for which accounts other than those designated as current are provided. There shall not be included in current assets any item, the amount or collectibility of which is not reasonably assured, unless an adequate provision for possible loss has been made therefore. Items of current character but of doubtful value may be written down and for record purposes carried at nominal value.

**3000 CASH**

Includes the amounts of current cash funds in three subdivisions:

1. 3000 - Cash in Bank
   3010 - Cash Over/Short

2. 3013 - Petty Cash

3. 3020 - Short-Term Investments - Investments with maturities less than one year.

4. **3030 - Bank Indebtedness**

**3100 ACCOUNTS RECEIVABLE**

The range of account numbers 3100 - 3199 encompasses the Accounts Receivable of the company. Within this range are sub-ranges which are grouped for reporting purposes in the monthly financial statements.

**3100 <u>Accounts Receivable - Electric</u>**

Includes amounts due from customers for electricity consumption billed to them on a monthly basis in accordance with established rates approved by the Island Regulatory and Appeals Commission.

**3101 <u>Allowance for Doubtful Accounts</u>**

Credited with estimated provision for losses on accounts receivable which may become uncollectible. Write-offs, usually on an annual basis, are charged against this account. The year-end balance is then adjusted through Uncollectible Accounts Expense (See 8002) to provide a reasonable provision against Accounts Receivable losses for the ensuing year.

**3102 <u>A/R OATT</u>**

**3103 <u>A/R Service Orders</u>**

**3104 <u>COVID-19 Customer Support Program</u>**

Records and tracks the amounts deferred, collected and recovered by eligible customers participating in the COVID-19 Customer Support Program.

**3105 <u>ECAM Re Lepreau Replacement Energy</u>**

**3106 <u>ECAM Receivable Current</u>**

**3107 Cost of Capital**

**3108 ECAM 2003 Receivable**

**3109 Def Lepreau Writedown Current**

**3110 Lepreau OMA & Replacement Energy Receivable**

**3111 Accounts Receivable - HST**

This account shall include all GST paid on Goods and Services purchased by the Company. At the end of the month, the balance in this account is netted against the GST collected on monthly sales (See 4311). The resulting balance is recorded in account 3112.

**3112 HST Refund Receivable**

This account records the balance of GST refundables.

**3115 Energy Rebate**

This account records balance of Energy Rebate to eligible energy customers on PEI.

**3117 Other Post Employment Benefits - Current**

This account is for the current portion of Other Post Employment Benefits that arise upon actuarial re-measurements of the Companies Post Employment Benefits Plan.

**3118 Storm Deferral - Current**

This account is for the current portion deferred as a result of extreme weather events.

**3119 CTGS Unrecovered Depreciation – Current**

This account is for the current portion of the Charlottetown Thermal Generating Station Reserve Variance deferral – see account 9412

**3120 Accounts Receivable – Construction**

Includes amounts invoiced from charges collected by job orders. Refer to Accounts 37XX to 39XX.

**3124 Accounts Receivable – FortisUS**

Includes amounts invoiced to FortisUS Energy Corporation – refer to Account 3185.

**3125 Accounts Receivable – Intercompany Invoiced**

Includes amounts invoiced to other Fortis Inc. companies. Refer to Accounts 3175-3179 and 3186.

**3127 Accounts Receivable – Oil Plan Retirees**

**3128 Accounts Receivable – LTD Maternity**

Includes amounts invoiced for health benefits paid by the Company for employees on long-term disability or maternity leave.

**3130 Accounts Receivable – City of**

**3150 Income Tax Receivable**

Includes Income Tax receivable from Canada Customs and Revenue Agency.

**3151 Future Income Tax – Current**

**3155 Demand Side Management (DSM)**
Includes current year portion of DSM.

**3160 Accounts Receivable – General Office**
Includes amounts due from employees, usually in the form of travel advances. When expense accounts are submitted, the expenses are charged to the appropriate accounts and credited against the advances. Expenses less than advances are recoverable from the employee and if expenses are greater the difference is paid to the employee.

This account is also used in cases where training courses are partially paid for by the Company, in which case unpaid balances are due from the employee.

**3161 Accounts Receivable - Miscellaneous**
Includes charges for Holland College steam bills, unpaid contractors service work setup from the sales register, sale items such as poles, meters, lock boxes, etc. Allows Maritime Electric to further bill unpaid accounts.

**3162 Accounts Receivable – Oil Plan Employees**

**3163 Accounts Receivable – Appliance Account**
Please refer to Procedure #800006.

**3164 Accounts Receivable – Fitness Club Account**
Please refer to Procedure #800006.

**3165 Accounts Receivable Employee Computer Purchases**
Please refer to Procedure #800006.

**3166 Accounts Receivable Union (IBEW) Reimburse Maritime Electric Labour**
Amounts due from IBEW.

**3169 Accounts Receivable – Billing Holdbacks**
Includes amounts invoiced for holdbacks on construction job order projects.

**3170 Accounts Receivable – Pole Rental**
Amounts due for joint pole use for cablevision wires strung on the Company's lines.

**3171 Accounts Receivable – Pole Rental Adjustment**

**3173 Accounts Receivable – Share Plan Loan**
Includes amounts receivable from employees for share plan load advances.

**3174 Accounts Receivable – Fortis Trust Mortgage Payment**

**3180 Accounts Receivable – Property Rent**
This account includes all rents receivable from the Company's tenants in its property holdings.

**3175 – 3179** **Intercompany Receivables**

**3185 – 3189** These accounts are used to collect charges that will be billed to other Fortis companies. Refer to Accounts 3124 and 3125.

## 3200-3299 MATERIALS AND SUPPLIES

Except for line hardware (see below), this section includes gross costs, of all materials and supplies purchased primarily for use in the utility business for construction, operation, and maintenance purposes.

**3200** **Material and Supply Line Hardware**
Includes all materials specifically purchased for construction, repair and maintenance of lines recorded at a standard cost at time of receipt. When received the value of the materials is recorded at cost to 3200 and credited to 3210 (see below).
This account also includes, at average cost, material recovered as a result of salvage or retirement, if the material is re-usable or over-requisitioned, and credited to construction, maintenance or retirement Project Codes. The account is credited with the average cost of materials requisitioned for construction, maintenance and repair.

**3205** **PST Material and Supply Line Hardware**
Records the Provincial Sales Ta component of materials and supply line hardware.

**3210** **COGP (Cost of Goods Purchased) Line Hardware**
This holding account is credited with the purchase order cost of material and supply line hardware when the material receipt is processed. The account is debited during invoice matching in Accounts Payable. (See also 3200)

**3212** **COGP (Cost of Goods Purchased) Price Variance**
This account is charged for price variances approved between the purchase order and invoiced price for material and supply line hardware.

**3215** **COGP (Cost of Goods Purchased) Other**
This holding account is credited with the purchase order cost of material and supply line hardware when the material receipt is processed. The account is debited during invoice matching in Accounts Payable. (See also 3200)

**3217** **COGP (Cost of Goods Purchased) Other Price Variance**
This account is charged for price variances approved between the purchase order and invoiced price.

**3220** **Material Quantity Variance**
This account includes charges arising from variances in physical counts from perpetual records. The offsetting debits and credits are to 3200.

**3240** **Fuel Inventory Charlottetown - Bunker C**
The actual invoiced cost of Bunker "C" fuel is charged to this account and the liability for purchase is credited to 4350, Account Payable, Fuel Inventory - Charlottetown. Amounts are charged to expense as the fuel is used.

**3241 Fuel Inventory Borden**
The actual invoiced cost of diesel fuel is charged to this account and the liability for purchase is credited to 4360, Account Payable, Fuel Inventory - Borden. Amounts are charged to expense as the fuel is used.

**3242 Fuel Inventory Charlottetown – Diesel**
The actual invoiced cost of diesel fuel is charged to this account and the liability for purchase is credited to 4362, Account Payable, Fuel Inventory Charlottetown - Diesel. Amounts are charged to expense as the fuel is used.

## 3300-3399 PREPAYMENTS

**3300 Prepaid Insurance**
Includes the amount of premiums on insurance policies paid in advance. Premiums are credited monthly over the term of the policy to this account and charged to expense (See 8602).

**3301 Prepaid Miscellaneous**
Includes miscellaneous prepayments (i.e. software and interest).

**3302 Prepaid Sports**

**3305 PR Hourly Clearing**

**3310 Prepaid Tank Lease**

**3330 Prepaid Regulation**
Each year the Island Regulatory & Appeals Commission (IRAC) makes an assessment based on revenue as indicated in the Annual Report to the IRAC. This assessment is paid in advance and is pro-rated over a twelve-month period to expense (see 8510).

**3335 Prepaid Telephone – Consolidated Bill**
Monthly payment for consolidated telephone bill is charged to this account and cleared by allocation journal entry.

**3336 Prepaid Telephone – Miscellaneous Bills**
Monthly payment for cell phones and pages is charged to this account and cleared by allocation journal entry.

**3350 Prepaid Flagging**
Monthly payment for flaggers is charged to this account and cleared by allocation journal entry.

**3360 Inventory Interest Allocation**

**3361 – 3393 Pre-charged Inventory**
Stock issued to pre-charged accounts is charged to this account and cleared by allocation journal entry.

## 3400-3499 OTHER CURRENT ASSETS

**3400** **Transportation Expense Unallocated**
Includes all charges relating to company and leased vehicles. Charges to expense monthly are based on the pro-rata calculation of monetary value per truck-hour, i.e. total expenses divided by total hours.

**3403** All vehicles that are class 01, 02, 03 and 04 are to be charged to this account number.

**3405** All vehicles that are class 05 and class 06 are to be charged to this account number.

**3407** All vehicles that are class 07 and 08 are to be charged to this account number.

**3410** All vehicles that are class 10 and 80 are to be charged to this account number.

**3412** All vehicles that are class 11, 12, **40** and 86 are to be charged to this account number.

## 3500-3599 DEFERRED CHARGES AND LONG-TERM PORTION OF REGULATORY ASSETS

3500 Deferred Generation Planning **(inactive)**

**3502** **WNRA (Weather Normalization Regulatory Asset)**

**3504** **Storm Deferral – Long-Term**
This account is for the long-term portion of the Charlottetown Thermal Generating Station Reserve Variance deferral – see Account 9412.

**3505** **Deferred Acquisitions (Inactive)**

**3507** **Deferred Lepreau Writedown**

**3508** **Lepreau Replacement Energy**

**3510** **Deferred Marketing (Inactive)**

3520 Demand Side Management (DSM)

**3525** **OPEB (Other Post Employment Benefits) Regulatory Deferral**

**3534 – 3539** **Deferred Financing Fees**

3550 **ECAM Receivable LT**

3560 **Corporate Income Receivable**

3580 **ROW and Easements**

### 3580 RIGHTS-OF-WAY AND EASEMENTS

Charge to this account the cost of all easements and rights-of-way acquired and used primarily for distribution or transmission of electric power from one point to another. It will include cost of land survey, payments made to land owners, cost of examination, searching and confirmation to title, registration of easement of right-of-way, cost of mortgage releases, conveyancers' and notaries' fees, etc.

**3580 Rights-of-Way and Easements**

### 3582 ACCUMULATED AMORTIZATION – RIGHTS-OF-WAY AND EASEMENTS

**3582 Accumulated Amortization - ROW**

### 3585 INTERNALLY DEVELOPED SOFTWARE

**3585 Internally Developed Software**

### 3586 ACCUMULATED AMORTIZATION – INTERNALLY DEVELOPED SOFTWARE

**3586 Accumulated Amortization – Internally Developed Software**

### 3600-3699 LONG-TERM INVESTMENTS

3600 Investment in FortisUS
3610 Long-Term Investments

### 3700-3999 ACCOUNTS RECEIVABLE JOB ORDERS

**3700 - 3850**

**3900 Other Job Orders**

**Long-Term Liabilities**

Includes until maturity, all debts and obligations which are not required to be liquidated within one year. These should be segregated as between the main classes, e.g. Funded Debt (bonds) which will have a subdivision for each class and series of bonds.

**Current Liabilities**

Includes all liabilities payable within one year from the date of the balance sheet, and the total of the current liabilities should be shown. Liabilities payable within one year but for which special provision has been made from other than current resources may properly be excluded from the current liability classification, e.g. a maturing bond issue which is to be refinanced.

Current liabilities should be segregated as between the main classes, e.g. bank loans, trade creditors, and accrued liabilities, loans payable, taxes payable, dividends payable and current payments on long-term debt.

**4000 FUNDED DEBT**

Includes in a separate division for each class and series of bonds the face value of the issued and unmatured bonds which have not been retired or cancelled.

**See 4000 to 4009 in Code of Accounts**

**4200-4299 PAYROLL – DEDUCTIONS AND OVERHEADS**

The range of 4200 - 4299 includes all those accounts relating to payrolls payable and the deduction payable to third parties.

| | |
|---|---|
| 4200 | Payrolls Payable |
| 4204 | Payroll Supplementary Pension Benefits |
| 4205 | Payroll Post-Retirement Benefits |
| 4206 | Payroll Post-Employment Benefits |
| 4207 | Accrued Liability Pension |
| 4209 | Payroll Voluntary RRSP |
| 4210 | Payroll Additional AD&D |
| 4212 | Retirement Allowances |
| 4214 | Payroll LTD |
| 4222 | Payroll Basic AD&D |
| 4224 | Payroll OH Regular RRSP |
| 4228 | Payroll Choices |
| 4229 | Choices MGMT Fund |
| 4232 | Payroll Life Insurance |
| 4233 | Payroll Health and Dental |
| 4234 | Payroll **Payable LTD Health Benefits** |
| 4235 | Payroll Overtime RRSP |
| 4236 | Payroll **Executive Compensation Program** |
| 4237 | Payroll Administration |
| 4239 | Payroll Temporary Assessment |
| 4299 | Payroll Employee Banked Time |

## 4300-4399 ACCOUNTS PAYABLE

The range of 4300 - 4399 includes all those accounts representing amounts payable by the Company within one year which is not provided for in other accounts.

| | |
|---|---|
| 4300 | Bank Loan |
| 4301 | Bankers' Acceptances (Refer also 3301) |
| **4305** | **Intercompany Loan** |
| **4307** | **Current Portion of LTD** |
| 4310 | A/P Vouchers |
| **4311** | **HST Payable** |
| 4312 | A/P Regulation |
| 4316 | A/P Clearing Account |
| **4317** | **A/P Intercompany Clearing** |
| **4318** | **Share Plan Contributions** |
| 4320 | A/P Material Received Not Invoiced |
| 4325 | Wind Power Premiums |
| 4330 | A/P Year End |
| 4331 | HST Remittance Payable |
| 4335 | Rate Rebate |
| 4340 | A/P Energy Purchases |
| 4350 | Fuel Inventory – Charlottetown Bunker |
| **4351** | **A/P Facilities Use Charge** |
| 4360 | Fuel Inventory – Borden |
| 4362 | Fuel Inventory – Charlottetown Diesel |
| 4370 | Provincial Sales Tax Payable |
| **4372** | **A/P Dalhousie Recovery Ryder** |
| 4373 | Lepreau Ryder |
| **4374** | **A/P Cable Contingency Ryder** |
| 4374 | Cable Contingency Ryder |
| 4375 | Cable Interconnection Financing |
| **4380** | **A/P Borden Generating Station** |
| 4390 | Holdbacks From Suppliers |

## 4400-4499 ACCRUED LIABILITIES

The ranges 4400 - 4499 include all those accounts classified as accrued and other current liabilities which are defined as those obligations which have either matured or which become due within one year.

| | |
|---|---|
| 4400 | Accrued Income Tax Payable |
| 4410 | Customers Deposits |
| 4411 | **Gift Certificates** |
| 4420 | Accrued Taxes Other |
| 4421 | Accrued Liability - Special Pension Expense |
| **4426** | **Rebate Interim Industrial Assistance** |
| 4431 | Accrued Liability Audit |
| 4432 | Accrued Interest Customer Deposits |
| 4435 | **CIAC Deposit** |
| **4436** | **OPEB Regulatory Deferral Current** |
| **4437** | **Pre 2016 RORA Current** |
| 4438 | Costs Payable to Customers |

| | |
|---|---|
| **4440** | **Dividends Payable Preferred Shares** |
| 4450 | Dividends Payable - Common Shares |
| 4470 | Accrued Interest 2016 11.5% |
| 4471 | Accrued Interest 2018 8.55% |
| 4472 | Accrued Interest 2031 8.92% |
| 4473 | Accrued Interest 2027 8.625% |
| 4474 | Accrued Interest 2038 6.054% |
| **4476** | **Accrued Interest 2056 3.657%** |
| 4477 | Accrued Interest 2010 12% |
| 4478 | Accrued Interest 2025 7.57% |
| **4479** | **Accrued Interest 2061 4.915%** |
| **4525** | **Pre 2016 RORA** |
| **4526** | **Post 2015 RORA** |
| **4527** | **OPEB LT** |
| **4529** | **CAR** |

## 4500-4519 CONTRIBUTIONS FOR SERVICES

Includes contributions in cash from others for construction of service lines and extensions.

| | |
|---|---|
| 4500 | Contributions - New Services |
| 4501 | Amortization Contributions |
| 4503 | Contributions Extensions |
| 4505 | Contributions - Other |
| 4510 | Refundable Contributions |

## 4520 FUTURE SITE REMOVAL AND RESTORATION

**4520 Site Restoration Costs**

## 4600 FUTURE INCOME TAX

**4600 <u>Future Income Tax</u>**

This account is used to accumulate tax deferrals arising from differences between accounting income and taxable income in a given period. These "timing" differences arise from transactions that affect the determination of net income for financial accounting purposes in one reporting period and the computation of taxable income in a different (reporting) period. In addition, there are "permanent" differences which create tax deferrals within this same reporting period. These permanent differences may arise from situations where certain expenses and losses as well as certain revenues and gains will never be included in the computation of taxable income. Also, some deductions may be allowable for tax purposes even though they have no counterpart in the determination of accounting income. (Also refer NARUC 281, 282, 283 and CICA 3470.05 - 33; 3471.39-.44).

**4601 <u>Deferred CCA on Contributions</u>**

**4605 <u>Future Income Taxes Current</u>**

Current portion due within one year of Future Income tax (see 4600).

## 4700-4710 SHAREHOLDERS' EQUITY

These accounts include the par value or stated value in the case of stock without par value for each class of capital stock actually issued.

4710 Common Stock

## 4720 RETAINED EARNINGS

This account represents the accumulated balance of income arising from the operation of the business, after taking into account dividends and other amounts that may properly be charged or credited thereto.

Income and Surplus accounting covers the procedure to be followed in setting up the Income Account and the Surplus or Profit and Loss Account.

The Income Account
Includes the operating revenues and expenses, the other income and the various deductions applicable to the Company as a whole, for the current fiscal period.

Operating revenues shall include the total revenue from all classes of service. Operating expenses shall include the total operating expenses from all classes of service. The balance, after subtracting operating expenses from operating revenues, shall be termed "Net Operating Revenue".

Other income Accounts are those which are not assignable to any class of service of the Company and not considered as an earnings attributable to the direct operations of the Company. Other income accounts include such income as interest and dividends from investments.

Deductions from Gross Income include such items, for the Company as a whole, as bond interest, bank interest, interest on customers' deposits and other miscellaneous interest, less credit for interest charged to construction, amortization of discount on securities and appropriations for reserves. Where miscellaneous interest is earned in the various direct operations of the Company, it shall not be included in operating revenues but shall be treated as an offset or deduction from the interest expenses mentioned above. The balance after subtracting the Income Account deductions from the Gross Income shall be termed "Net Income". (This is what is termed "Net Earnings" in the Company's Annual Report).

The Surplus Account shall show the balance at the beginning of the fiscal period, plus or minus specified major adjustments, if any, from previous fiscal periods. To this adjusted balance shall be transferred the "Net Income" from the income account, against which shall be made the specific surplus account deductions such as dividends declared on Preferred and Common Stock. Special appropriations of an unusual nature should show as a separate and final deduction from the balance of the surplus account.

NOTE: Only major adjustments from previous fiscal periods should be charged or credited to the surplus account. Any minor adjustments should be absorbed in the prescribed classification of revenue and expense accounts in the current period.

**5000-5028 ACCUMULATED AMORTIZATION - GENERAL**
This account is credited with an estimated monthly accrual charged to depreciation expense adjusted at year-end to record accurate depreciation computed on total fixed assets. At retirement of depreciated utility plant in service, the accounts are charged with the book cost of the property retired and the cost of removal, and credited with salvage value and any other amounts recovered.

When retirements are made, cost of removal and salvage are entered originally in retirement Project Codes. (See also Project Code systems 2000 - 2999).

The following accounts record the amortization of contributions: (See 4500)

| | |
|---|---|
| 5000 | Accumulated Amortization General |
| 5050 | General Expense Retirement |

5051 General Expense Retirement Closing

**5100-5999 RETIREMENT PROJECT CODES IN PROGRESS**

A control account in the general ledger covers the subsidiary ledger balances for all retirement Project Codes.

Scrap Proceeds

Proceeds of sale of scrap metal (see Account UPDATE).

The Project Code system for retirements operates in the same fashion as capital Project Codes. Refer Section I, 2000 - 2999.

Operating Revenue accounts are those in which are recorded the amounts which the Company receives or becomes lawfully entitled to receive for services rendered and as a return on property used in the operations of the Company.

Revenue Accounts

They shall be divided into separate divisions for each class of service rendered by the Company. The accounts of each class of service shall be divided as between the accounts necessary to record Operating Revenues and Miscellaneous Revenue.

**6000-6400 ELECTRIC REVENUE ACCOUNTS**

These accounts include the net billing for the electricity supplied to the various classes of customers as detailed in the individual accounts listing below.

| | |
|---|---|
| 6200 | Residential |
| 6210 | General Service I |
| 6211 | General Service II |
| 6212 | General Service II |
| 6220 | Small Industrial |
| 6230 | Street & Yard Lighting |
| 6240 | Unmetered |
| 6241 | Service Connections |
| 6250 | Large Industrial |
| 6260 | Penalty Revenue |
| 6300 | Wholesale Rate |
| 6340 | Transmission Access |
| 6342 | Scheduling Service |
| 6344 | Reactive Supply and Voltage Control |
| 6346 | Cumulative Transmission Energy Losses |
| 6348 | Non-Capital Support Charge |

**6500-6599 OTHER REVENUES**

| | |
|---|---|
| 6502 | Steam Sales |
| 6604 | Interest During Construction |
| 6605 | Miscellaneous Revenue |
| 6606 | Accrued Revenue Adjustment |
| **6607** | **Commission Income Fortis Trust** |
| 6611 | Interest Income Miscellaneous |
| 6613 | Gain/Loss on Sales of Assets |
| 6615 | Billing Revenue |
| 6620 | Rental Property Income |
| 6622 | Rental Property Income Base WRSC |

The first subdivision of Operating Expense Accounts shall be into operating components:

1. Production Operating Expenses
2. Distribution Operating Expenses
3. Transmission Operating Expenses
4. General Expense

Production Operating Expense

Production Expense is the cost of operating and maintaining the properties defined under Production in the Fixed Capital Accounting text. The Production Operating Expense records shall be divided into each plant and at the discretion of the management, the Operating Expense of each plant may be subdivided into the prescribed classification for Production Operating Accounts.

Transmission and Distribution Operating Expenses

The Operating Expense of each line or group will be subdivided into the prescribed classification of Transmission and Distribution Operating Expense Accounts.

General Expense

The treatment of General Expense is defined in the section covering General Expense Accounts - Section VIII.

Operating Supervision

Where there are supervisors in charge of a group of Production Plants, Transmission Lines, Distribution, or in charge of any combination of these three main divisions of operations, an operating account shall be kept to record such "Operating Supervision" as a separate item for each main division or combination.

## 7000-7499 OPERATING EXPENSES

The ranges of operating expenses relating to Production are broken down as follows:

| | |
|---|---|
| 7000 - 7099 | Power Purchases |
| 7100 - 7199 | Charlottetown Steam Plant |
| 7200 - 7299 | Borden Gas Turbine Generating Plant |
| 7300 - 7399 | Maritime Interconnection Facilities - Company - Owned |
| 7400 - 7499 | Maritime Interconnection Facilities - Government - Owned |

## 7000-7009 POWER PURCHASES

**7000 NB Power – Assured**

This accounts for purchases of Assured Energy from NB Power through the Energy Purchase Agreement.

**7001 Regulation**

Regulation is an Ancillary Service under the NB Power Open Access Transmission Tariff and is the provision of generation and load response capability, including capacity, energy and maneuverability, that responds often and rapidly to automatic control signals issued by the Control Area operator

**7002 NB Power Capacity**
This accounts for the capacity included with the Firm Energy under the NB Power Energy Purchase Agreement

**7003 Assured Load Following**

**7004 Foreign Exchange**

**7005 Natural Gas Generation**

**7006 Slemon Park Capacity**
Provides for the purchase of 1 MW of capacity from Slemon Park Corporation.

**7007 Wing Energy**
Provides for the purchase of wind energy from large scale on Island wind producers.

**7008 Other Energy**
Provides for the purchase of renewable (excluding large scale wind) energy from on Island sources.

**7009 Reserve 10 Minute Spinning**
Provides for the purchase of 10 minute spinning reserve which is needed to serve load immediately in the event of a system contingency.

## 7010-7019 DALHOUSIE

**7010 Generation Fuel Costs**
Charges for the direct costs of fuel used in the operation of the Dalhousie generating facility. The billing is made in advance, estimating the amount and cost of fuel (coal and/or light oil) to be used during the month.

Other Information
The estimated billing also includes plus or minus adjustments of prior months to correct the then estimates. The billing can also include estimates for energy supplied from other sources.

**7011 Inventory Charge**
Monthly charges for storing generating fuel by NB Power at Dalhousie, apportioned to Maritime Electric on the % ownership basis.

Other Information
This charge is based on actuals of the second preceding month and uses daily inventory values at a prescribed interest rate producing a total carrying charge for the month which is then allocated to Maritime Electric on the % ownership basis.

**7012 Operating and Maintenance Costs**
Charges billed to Maritime Electric for the operation and maintenance of the Dalhousie unit. As with Account 7010 this is an advance billing.

Other Information
This estimated billing includes plus or minus adjustments of prior months to correct the estimates previously billed.

**7013 Operators Fees**
Charges billed monthly in accordance with the terms of the Dalhousie agreement.

Other Information
The charge is derived from Maritime Electric ownership participation cost as accounted for by NB Power using an escalating factor to arrive at current value at a pre-determined annual percentage on a monthly basis.

**7014 Transmission Agreement**
Charges billed for the transmission of energy from Dalhousie to the point of cross-over to Maritime Electric at Murray Corner.

Other Information
The billing for the transmission charge is calculated using

- capacity charges
- depreciation of transmission lines
- capacity valuation of transmission and transformers
- O & M charges

**7015 Dalhousie Cost of Capital**
Monthly financing charge.

**7016 Dalhousie Inventory (Common Stock)**
Monthly charge for carrying common stock inventory.

## 7020-7039 POINT LEPREAU

**7020 Lepreau Fuel**
Charges for the direct costs of fuel used in the operation of the Dalhousie generating facility. The billing is made in advance, estimating the amount and cost of fuel (coal and/or light oil) to be used during the month.

Other Information
The estimated billing also includes plus or minus adjustments of prior months to correct the then estimates. The billing can also include estimates for energy supplied from other sources.

**7021 Lepreau Cost of Carrying Fuel**
Monthly charges for storing generating fuel by NB Power at Point Lepreau, apportioned to Maritime Electric on the percent ownership basis.

**7023 Lepreau Cost of Capital**
Monthly financing charge.

**7025 Lepreau Operating Maintenance and Indirect**
Charges billed to Maritime Electric for the operation and maintenance of the Point Lepreau unit. As with Account 7010 this is an advance billing.

Other Information
This estimated billing includes plus or minus adjustments of prior months to correct the estimates previously billed.

**7027 Lepreau Decommissioning Charge**
Monthly charge to cover future decommissioning of Point Lepreau Generating Station.

**7029 Lepreau Guarantee Fee**
Monthly loan guarantee fee.

**7031 Lepreau Inventory Common Stock**
Monthly charge for carrying common stock inventory.

**7033 Lepreau Heavy Water**
Monthly charge for handling heavy water.

## 7040-7099 OTHER

**7040 Operating and Maintenance Transmission Lines – NB Power**
Monthly operating and maintenance charges from NB Power for use of transmission lines.

**7041 Operating and Maintenance Memramcook**
Monthly operating and maintenance charges from NB Power for use of transmission lines.

**7042 Breaker Rental – NB Power**
Monthly breaker rental charge from NB Power.

**7043 Reserve 10 Minute Non-Spinning**
Provides for the purchase of 10 minute non-spinning reserve which is needed to serve load immediately in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time.

**7044 Reserve 30 Minute Non-Spinning**
Provides for the purchase of 30 minute non-spinning reserve which is needed to serve load immediately in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time.

**7045 Load Following**
Load Following is an Ancillary Service under the NB Power Open Access Transmission Tariff and is the provision of generation and load response capability, including capacity, energy and maneuverability, that is dispatched within the scheduling period by the Control Area operator at frequencies and rates that are lower and slower than regulation.

**7046 NB Power Secure**
This accounts for purchases of Secure Energy from NB Power through the Energy Purchase Agreement.

**7047 NB Power Interruptible**
This accounts for purchases of Interruptible Energy from NB Power through the Energy Purchase Agreement.

**7048 NB Power Curtailled**
This accounts for the purchase of energy from NB Power when Energy products under the NB EPA have been curtailed economically but not physically.

**7049 Capacity – Other**
This allows for the purchase of system capacity from sources other than the NB Power Energy Purchase Agreement.

**7050 NB Power Firm**
This accounts for purchases of Firm Energy from NB Power through the Energy Purchase Agreement; however it does not provide for the corresponding capacity.

**7051 Inadvertant Energy**
This provides for the purchase and sale of energy within the imbalance bandwidths from the NB System Operator when load schedules do not match actual load.

**7052 Other Energy**
This provides for the purchase of energy from sources outside the NB Power Energy Purchase Agreement, wind energy, on Island renewable energy and the City of Summerside.

**7053 Imbalance Energy**
This provides for the purchase and sale of energy outside the imbalance bandwidths from the NB System Operator when scheduled loads do not match actual loads.

**7054 Imbalance Premium**
This provides for the punitive penalty portion of the imbalance bill from the NB System Operator when scheduled loads do not match actual loads. No energy is included.

**7055 Summerside Energy Purchase**
This provides for the purchase of energy from the City of Summerside.

**7056 E-Tagging and Scheduling**
This provides for the fees required to utilize the e-tagging system for entering energy requirements.

**7057 Cost of Energy for Sales**
This provides for the cost of energy that are then sold to another party (not Maritime Electric).

**7058 IPL Transmission Scheduling**
This provides for the costs associated with the International Power Line contract and other related costs.

**7090 ECAM Recovery**

## 7100-7199 CHARLOTTETOWN STEAM PLANT

**7102 Charlottetown Thermal Generating Station Buildings and Services**
Cost of maintaining thermal power plant buildings, permanent fixtures therein and other buildings and structures in and about thermal generating plant which are used for production purposes.

Salaries and wages of employees in the Steam Generating Plant, whose time is not chargeable to any of the operating accounts; and miscellaneous expenses not chargeable to other accounts.

Labour:
1. General clerical and stenographic work.
2. Guarding and patrolling plant and yard.
3. Building heating, ventilation, electrical and communication services.
4. Care of grounds including snow removal, cutting grass, etc.
5. Miscellaneous labour.

Materials and Expenses:
6. General operating supplies, such as tools, gaskets, packing waste, gauge glasses, hose, indicating lamps, records and report forms, etc.
7. First aid supplies and safety equipment.
8. Employees service facilities expense.
9. Building service supplies.
10. Electrical and communication services.
11. Miscellaneous office supplies and expenses, printing and stationery.
12. Transportation expense.
13. Meals (while traveling) and incidental expenses.
14. Annual payment to Cumberland Trust for lease of land at Charlottetown Plant.
15. Costs associated with the operation and maintenance of emergency generators used to start auxiliaries in case of power failure.

**7103 Charlottetown Thermal Generating Station Maintenance**
Costs of maintaining the building, mechanical and electrical equipment.

**7105 Charlottetown Thermal Generating Station Operations**
All costs pertaining to the operation of Boiler units 1 - 10 in the Charlottetown Plant. Salaries and wages of employees involved in an operational capacity are charged to this account as well as other expenses incurred therefore:

1. Supervising steam production.
2. Operating boiler and boiler auxiliary equipment.
3. Keeping boiler plan log and records and preparing reports on boiler Plant operation.

4. Boiler water demineralization, testing and water supply.
5. Operating fuel conveying, storage, weighing and processing equipment within Plant.

**7114 CTGS Electrical Equipment Maintenance**

**7116 Charlottetown Thermal Generating Station Superintendence**

Salaries and related expenses of superintendents and assistants, chemists, day and night foremen and station clerks. The account should include a portion of the salaries of superintendents or managers whose jurisdiction extends over the entire Company operations.

**7117 Charlottetown Thermal Generating Station Buildings Generation Fuel - Bunker**

Cost of fuel used in the production of steam for the generation of electricity.

Other Information

The fuel costs is initially charged to the inventory Account 3240 and, on the basis of fuel used, credited out and charged to Account 7117 each month.

**7122 Steam Supply - Fuel**

**7130 Generation Fuel Diesel - Charlottetown**

**7150 ECC Operations**

All costs pertaining to the operation of Energy Control Centre (ECC) operations.

## 7200-7299 BORDEN GAS TURBINE GENERATING PLANT

**7202 Borden Generating Station Building and Services**

Cost of maintaining power plant buildings, permanent fixtures therein and other buildings and structures in and about generating plant which are used for production purposes.

Salaries and wages of employees in the Generating Plant, whose time is not chargeable to any of the operating accounts; and miscellaneous expenses not chargeable to other accounts.

Labour:

1. General clerical and stenographic work.
2. Guarding and patrolling plant and yard.
3. Building heating, ventilation, electrical and communication services.
4. Care of grounds including snow removal, cutting grass, etc.
5. Miscellaneous labour.

Materials and Expenses:

6. General operating supplies, such as tools, gaskets, packing waste, gauge glasses, hose, indicating lamps, records and report forms, etc.
7. First aid supplies and safety equipment.
8. Employees service facilities expense.
9. Building service supplies.
10. Electrical and communication services.

11. Miscellaneous office supplies and expenses, printing and stationery.
12. Transportation expense.
13. Meals (while traveling) and incidental expenses.
14. Costs associated with the operation and maintenance of emergency generators used to start auxiliaries in case of power failure.

**7209 <u>Borden Generating Station CT Operating</u>**
All costs incurred in the operation of the Borden gas turbines, Units 1 and 2. Salaries and wages of employees involved in an operational capacity, as well as other charges incurred, are charged to this account.

**7210 <u>Borden Generating Station CT Maintenance</u>**
Costs incurred in the maintenance of the gas turbine units at Borden. The charges should include salaries and wages of employees, and materials involved in maintaining the steam turbines, as well as other expenses incurred therefore.

**7217 <u>Borden Generating Station CT Fuel - Diesel</u>**
Cost of fuel used for the purpose of generating electricity at the Borden Gas Turbine facility. The source of this cost comes from the calculation of fuel used as per monthly statistical report.

<u>Other Information</u>
The fuel cost is initially charged to the inventory Account 3241 and, on the basis of fuel used, credited out and charged to Account 7217 each month.

## 7300-7349 CHARLOTTETOWN THERMAL GENERATING STATION CT

**7302 <u>Charlottetown Thermal Generating CT Station Building and Services</u>**
Cost of maintaining power plant buildings, permanent fixtures therein and other buildings and structures in and about generating plant which are used for production purposes.

Salaries and wages of employees in the Generating Plant, whose time is not chargeable to any of the operating accounts; and miscellaneous expenses not chargeable to other accounts.

<u>Labour:</u>
1. General clerical and stenographic work.
2. Guarding and patrolling plant and yard.
3. Building heating, ventilation, electrical and communication services.
4. Care of grounds including snow removal, cutting grass, etc.
5. Miscellaneous labour.

<u>Materials and Expenses:</u>
6. General operating supplies, such as tools, gaskets, packing waste, gauge glasses, hose, indicating lamps, records and report forms, etc.
7. First aid supplies and safety equipment.
8. Employees service facilities expense.
9. Building service supplies.
10. Electrical and communication services.
11. Miscellaneous office supplies and expenses, printing and stationery.

12. Transportation expense.
13. Meals (while traveling) and incidental expenses.
14. Costs associated with the operation and maintenance of emergency generators used to start auxiliaries in case of power failure.

**7303 Charlottetown Thermal Generating Station CT Maintenance**
Costs of maintaining the building, mechanical and electrical equipment.

**7305 Charlottetown Thermal Generating Station CT Operating**
Cost of maintaining power plant buildings, permanent fixtures therein and other buildings and structures in and about generating plant which are used for production purposes.

**7317 Charlottetown Thermal Generating Station CT Maintenance**
Cost of fuel used for the purpose of generating electricity at the turbine facility. The source of this cost comes from the calculation of fuel used as per monthly statistical report.

## 7350-7399 PRODUCTION OTHER

**7350 Charlottetown Thermal Generating Station CT - Insurance**

**7355 Charlottetown Thermal Generating Station CT - Property Tax**

## 7400-7499 MARITIME INTERCONNECTION FACILITIES – GOVERNMENT-OWNED

**7400 Provincial Debt Repayment**
This account is for the monthly payment to the Prince Edward Island Energy Corporation for the repayment of provincial government debt related to Point Lepreau refurbishment and Dalhousie Generation Station retirement. Per UE23-04 *"Costs recoverable from ratepayers on behalf of the Province of Prince Edward Island related to debt repayment costs shall no longer be collected as a rate rider and shall instead be included in the revenue requirement and collected during the period May 1, 2023 to February 28, 2026."*

**7415 M.I.C.F. Government-Owned Miscellaneous Labour and Expense**
This account should include costs incurred in the maintenance of Government-owned facilities associated with the Maritime Interconnection that are not chargeable to any of the foregoing accounts; and miscellaneous expenses not chargeable to other accounts.

**7441 M.I.C.F. Government-Owned Bedeque Substation**
This account covers the costs of maintenance of all equipment owned by the Province of Prince Edward Island, contained within Bedeque Substation, and shall include charges for labour, materials, meals, transportation, etc.

## 7500-7599 OPERATING EXPENSES – OATT

**7500 Transmission Access**

**7502 Scheduling Service**

**7503 Wind Regulation and Load Following**

**7504 Reactive Supply and Voltage Control**

**7507 Residual Uplift (Expense)**

**7508 Non-Capital Support Charge**

**7510 OATT**

## 7700-7799/7800-7899 OPERATING EXPENSES - TRANSMISSION AND DISTRIBUTION

The two ranges of operating expenses relating to the Transmission and Distribution systems are broken down as follows:

| | |
|---|---|
| 7700 - 7799 | Distribution |
| 7800 - 7899 | Transmission |

**7741/7841 Maintenance - Substation Equipment, Buildings, Structures and Grounds**

Charge to this account the cost of operating and maintaining substation and grounds (substations being any substation located either on transmission system or on the distribution system to step up or step down the voltage for the convenience of the customer or the Company).

These costs include:

1. Repairs to furniture, fixtures, and other property in and around the main substation.
2. Maintenance of adjacent grounds.
3. Substation labour including wages and janitors, watchmen, and operators in the substation.
4. The cost of supplies and expenses in connection with the operation of distribution substations such as transportation, meals, telephone, stationery and printing tool expense, heat, janitor's supplies, etc.

**7745/7845 Maintenance – Rights of Way and Easements**

Costs incurred in the upkeep and repair of Company-owned distribution and transmission rights-of-way.

**7847 Maintenance - Transmission Towers**

This account should include the costs incurred in the repair and upkeep of Company-owned distribution and transmission lines.

Work of the following character on transmission towers, and fixtures:

a. Installing or removing additional clamps or strain insulators on guys in place.
b. Painting towers.
c. Readjusting and changing position of guys or braces.
d. Realigning and straightening towers, braces and other tower fixtures.
e. Relocating fixtures on towers.
f. Repairing or realigning pins, racks, brackets or structural members.
g. Supporting fixtures and conductors and transferring them to new towers during replacements.

**7748/7848** **Maintenance - Lines**

This account should include the costs incurred in the repair and upkeep of Company-owned distribution and transmission lines.

1. Work of the following character on poles and fixtures:
    a. installing or removing additional clamps or strain insulators on guys in place,
    b. moving line or guy pole in relocation of the same pole or section of line,
    c. painting poles, crossarms or pole extensions,
    d. readjusting and changing position of guys or braces,
    e. realigning and straightening poles, crossarms, braces and other pole fixtures,
    f. relocating crossarms, racks, brackets, and other fixtures on poles,
    g. repairing or realigning pins, racks, or brackets,
    h. repairing pole supported platform,
    i. shaving, cutting rot, or treating poles or crossarms in use or salvaged for use,
    j. stubbing poles already in service,
    k. supporting fixtures and conductors and transferring them to new poles during pole replacements.

2. Work of the following character on overhead conductors and devices:
    a. overhauling and repairing line cutouts, line switches, line breakers etc.,
    b. cleaning insulators and bushings,
    c. refusing cutouts,
    d. repairing line oil circuit breakers and associated relays and control wiring,
    e. repairing grounds,
    f. resagging, retying, or rearranging position or spacing of conductors,
    g. standing by phones, going to calls, cutting faulty lines clear, or similar activities at times of emergencies,
    h. sampling, testing, changing, purifying, and replenishing insulating oil,
    i. repairing line testing equipment,
    j. transferring loads, switching and reconnecting circuits and equipment for maintenance purposes,
    k. trimming trees and clearing bush.

**7750/7850** **Maintenance - Lines Control Devices**

This account should include all costs incurred in the maintenance of line control devices on Company-owned distribution and trans- mission lines.

**7751** **Maintenance - Transformers**

Includes the cost of resetting, changing, inspecting, testing, and removing transformers on customers' premises or on poles, hand tools and supplies used in this work; when such transformers are installed for the purpose of stepping down current from transmission or distribution voltages to the voltage at which it is used by the customer. Includes the cost of maintenance, renewing oil, repairing, rewinding, repainting, repairs to cutouts, lightning arrestors, other than those in generating and substations. (Ref. 1651, 1751.)

**7753 Maintenance - Service Lines**
Include the cost of wire, insulating material, removing, replacing, and repairing switches and cutouts that are the property of the company - used in maintaining services, both underground and overhead leading from the distribution lines to the customers' premises. (Ref 1653, 1753)

**7754 Maintenance - Street and Yard Lighting**
This account will include the cost of labor, materials used, and other costs associated with the operation and maintenance of street and yard lighting installations.

1. supervising street lighting operation,
2. replacing lamps and incidental cleaning of glassware and fixtures in connection therewith,
3. routine patrolling for lamp outages, extraneous nuisances or encroachments, etc.,
4. testing lines and equipment including voltage and current measurements,
5. street lamp renewals,
6. transportation and tool expense,
7. meals, travelling and incidental expenses.

(Ref. 1754)

**7755 Maintenance - Underground Cables and Conduits**
This account includes all charges for operation and maintenance of underground cables and conduits used in the distribution of electricity, including such charges as repairs, testing, switching, inspecting, and expenses such as miscellaneous consumable tools and materials used in maintenance, transportation expense, meals and operating supplies such as instrument charts, etc.

**7756 Maintenance - Underground Service Lines**
This account includes all charges for operating and maintenance of underground service lines used in the distribution of electricity. It includes such charges as repairs, testing, switching, inspecting and expenses for miscellaneous consumable tools and materials used in maintenance, transportation expense, meals and operating supplies.

**7757 Maintenance - Underground Street Lighting Supply**
This account includes the cost of labour, materials used, and expenses incurred in the maintenance of street lighting systems fed by underground supply lines. Charges include operations of systems owned by the Company for things such as supervision of street light operation, replacement of lamps, ballasts, fuses, etc., routine patrolling, repairs to underground circuits used in supplying the lighting, materials, meals, transportation, etc.

**7758 Maintenance - Meters**
This account should include the cost of labour, materials, used and expenses incurred in the operation of customer meters and associated equipment.

1. Labour and Materials
    a. supervising meter operations,

b. clerical work on meter history and associated equipment record cards, test cards and reports,
c. consolidating meter installations due to elimination of separate meters for different rates of service,
d. changing or relocating meters, instruments transformers, time switches and other metering equipment,
e. resetting time controls, checking operation of demand meters and other metering equipment, when done as an independent operation,
f. inspecting and adjusting meter testing equipment,
g. meter seals and miscellaneous meter supplies,
h. transportation expenses,
i. meals, travelling and incidental expenses,
j. tools,
k. wages of meter foreman and staff of Meter Department,
l. cost of testing and inspecting customer meters performed by company or government,
m. cost of maintaining meters - replacement parts, cleaning, adjusting.

**7759 Maintenance – Meter Reading**

**7760 Maintenance - Radio Communications Equipment**

This account covers the cost of repairs and maintenance to Company-owned communications systems including:

a. mobile radio system
b. point-to-point UHF system
c. power line carrier system
d. micro-wave system
e. fiber optic system

Charges to this account are for labour, materials and miscellaneous expenses incurred in operating and maintaining these systems.

**7763 Maintenance - Supervisory (SCADA) System**

This account covers the cost of maintenance and repair to Company-owned supervisory and control (SCADA) systems including:

a. Computer maintenance for dedicated computers (including maintenance contract costs)
b. Master station and principal hardware
c. Remote terminal units

Charges to this account are for supervision, labour, materials and miscellaneous expenses incurred in operating and maintaining these systems, but not including System Operator costs.

**7765/7865 Engineering**

This account should include the cost of labour and expenses incurred in the general supervision and direction of the operation of the distribution and transmission system.

**7768 Miscellaneous Labour and Expense**

This account should include the cost of labour, materials used and expenses incurred in distribution system operation not provided for elsewhere.

1. Labour
   a. general records of physical characteristics of lines and substations, such as capacitors, etc.,
   b. ground resistance records,
   c. joint pole maps and records,
   d. distribution system voltage and load records,
   e. preparing maps and prints,
   f. service interruption and trouble reports,
   g. general clerical and stenographic work,
   h. operating records covering poles, transformers, manholes, cables and other distribution facilities,
   i. janitor work at distribution office buildings, including snow removal, cutting grass, etc.

2. Materials and Expenses
   a. communication services,
   b. building service expenses,
   c. miscellaneous office supplies and expense, printing and stationery, maps, records and first-aid supplies.

**7781 Training**

Expenses of a general nature shall be charged to the various appropriate accounts, by department, as incurred within the normal day-to-day operations.

Certain general expenses directly related to capital as distinct from those of an operating nature shall be charged to Undistributed General Expense - Capital corresponding to the fixed capital subdivisions. (See also 2000 - 2099)

## 7900-7999 TRANSMISSION AND DISTRIBUTION - OTHER

**7950 Insurance**

**7955 Property Tax**

## 8000-8999 GENERAL EXPENSES

**8020 Customer Service Support**
General expenses for labour, materials and other expenses for employees covered under the Collective Agreement in the Customer Service Support Group.

**8030 Meter Reading**
Charges for wages and expenses of Meter Reading, stationery, printing and transportation costs associated with meter reading are charged to this account.

**8055 Damage Claims**
Cost, bill collectors, records and delinquent notices, payment agent fees, stationery and printing supplies, commissions paid for collecting, transportation expense, etc. NSF charges and reconnection fees (related to arrears collection) are credited to this account.

**8060 Collections**
Cost, bill collectors, records and delinquent notices, payment agent fees, stationery and printing supplies, commissions paid for collecting, transportation expense, etc. NSF charges and reconnection fees (related to arrears collection) are credited to this account.

**8065 Uncollectible Accounts**
Monthly accrual to cover uncollectible bills. From time to time certain accounts written off will be charged to this account and accounts written off which are subsequently collected will be credited thereto.

Other Information
The monthly accrual is obtained from the annual budget and makes provision for bad debt write-offs at year-end.

**8100 Supervisor**
General expenses for Management labour, materials and other expenses.

**8110 Administrative Support**
General expenses for labour, materials and other expenses of employees covered under the Collective Agreement in the Administrative Support Group.

**8130 Auditing Tax and Professional Services**

This account includes the monthly accrual for audit fees. It also includes audit fees related to special matters and studies performed by the Company's auditors (see also 4431).

It also includes charges for professional services as they relate to financial matters.

**8345 Head Office Property Expenses**

To this account will be charged all Operating Expenses associated with the operation and maintenance of 180 Kent Street. Included are expenses such as: fuel oil, electricity for the house service, elevator maintenance, janitorial service, property taxes, management fees and all other expenses associated with the common area.

**8350 Charlottetown Service Centre Office Expenses**

To this account will be charged all Operating Expenses associated with the operation and maintenance of the West Royalty Service Centre. Included are expenses such as: fuel oil, electricity for the house service, janitorial service, maintenance costs, snow removal and all other expenses associated with the property.

**8360 Roseneath Service Centre Office Property Expenses**

To this account will be charged all Operating Expenses associated with the operation and maintenance of the Roseneath Service Centre. Included are expenses such as: fuel oil, electricity for the house service, janitorial service, maintenance costs, snow removal and all other expenses associated with the property.

**8365 Summerside Service Centre Office Property Expenses**

To this account will be charged all Operating Expenses associated with the operation and maintenance of the Summerside Service Centre. Included are expenses such as: fuel oil, electricity for the house service, janitorial service, maintenance costs, snow removal and all other expenses associated with the property.

**8370 Substation Property Expenses**

To this account will be charged all Operating Expenses associated with the operation and maintenance of the substations. Included are expenses such as: fuel oil, electricity for the house service, janitorial service, maintenance costs, snow removal and all other expenses associated with the property.

**8415 Donations**

**8510 Regulation**

This account should include the expenses incurred by the Company in its transactions with regulatory commissions, including the annual assessment.

This also covers fees, retainers and expenses of counsel, solicitors, attorneys, clerks, attendants, witnesses and others whose services are procured specifically for the defense or prosecution of those petitions presented to a regulatory commission that affect the Company. It will also include the pay, travelling and other expenses of those specifically employed or assigned to ascertain the value of property owned or used by the Company, the cost of stationery and printing and other necessary expenses of a similar character.

**8602 Insurance**

This account should include the expense of premiums paid on all fire and liability insurance.

Note:
Insurance charges on automobiles should be charged to automobile expense clearing account. Refer to 34XX.

**8603 Legal**

This account should include only the costs incurred in obtaining legal assistance that is not provided for elsewhere.

**8605 Future Benefits**

**8606 Supplementary Retirement Pension**

**8607 Property Taxes**

This account should include the expense accrued for property tax levied on Company property. (Refer 4420)

**8613 Directors' Fees and Expenses**

This account will include fees paid to directors and expenses incurred by them while performing their duties as board members. This account may also be charged with legal expenses if such work involved advice or counsel on matters concerning the Company and themselves in their capacity as directors.

**8614 General Administrative Expenses**

This account will include all charges that are not assignable to any other General account in the 8600- 8699 range. General types of expenses will include office supplies, communication costs, photocopier and fax costs, courier and postage. This account will also include a portion of salaries and expenses of support staff when under the supervision of the executive officers of the company.

**8620 Environmental**

**8630 Audit, Tax and Professional Services**

**8640 Employee Training**

Costs associated with the enhancement of employees' knowledge in their positions in the examples of these costs would be:

- registration for attendance at short-term conferences and seminars
- tuition for longer-term education
- travel and accommodation costs

Other income and deductions accounts are those which are not assignable to any class of service of the Company and not considered as an earning incidental to the direct operations of the Company. Other income and deduction accounts include such items as bond interest, depreciation, interest during construction, interest on short-term borrowings, and the like.

**9000-9999 OTHER INCOME DEDUCTIONS**

This range of accounts includes charges not includible in other (operating) accounts and which are deductible in determining net income.

**9000 - 9099 <u>Interest on Funded Debt</u>**

Includes the amount of interest expensed on outstanding long-term debt issued or assumed by the utility, detailed as follows:

| | |
|---|---|
| 9000 | 2016 Issue 11.5% |
| 9001 | 2018 Issue 8.55% |
| 9002 | 2031 Issue 8.92% |
| 9003 | 2027 Issue 8.625% |
| 9004 | 2038 Issue 6.054% |
| **9006** | **2056 Issue 6.657%** |
| 9007 | 2010 Issue 12% |
| 9008 | 2025 Issue 7.57% |
| **9009** | **2061 Issue 4.915%** |

(See also 4000, 4470-9)

**9100 <u>Other Interest Expense</u>**

This account shall include interest on bank loans, customers' deposits, tax assessments, and other interest charges not provided for elsewhere.

**9105 <u>Weather Normalization Reserve Account</u>**

**9107 <u>Rate of Return Adjustment</u>**

**9108 <u>ECAM Recovery</u>**

**9110 <u>Other Interest Expense - Non-Deductible</u>**

This account shall include interest expense which is non-deductible for income tax purposes.

**9400 <u>Appropriation for Depreciation</u>**

Includes depreciation expense for all classes of depreciable property. The company is required to keep records of property and property retirements as will reflect the service life of property which has been retired and also such records as will reflect the percentage of salvage and cost of removal for property retired.

**9411 <u>Amortization - Marketing</u>**

**9412** **Amortization – Charlottetown Thermal Generating Station Reserve Variance**
(formerly amortization of Lepreau - SLAR)
This account is to amortize the $10,672,276 Charlottetown Thermal Generating Station Reserve Variance deferral on a monthly basis over the period January 1, 2023 to December 31, 2027, as directed by the Island Regulatory and Appeals Commission in UE23-04. The associated regulatory assets accounts are 3119 CTGS Unrecovered Depreciation – Current and 3504 CTGS Unrecovered Depreciation – Long-Term.

**9415** **Amortization – Lepreau Writedown**

**9420** **Amortization – DSM Costs**

**9425** **Amortization – Developed Software**

**9427** **Amortization – Right-of-Way and Easements**

**9500** **Dividends Declared**
This account includes amounts declared payable out of retained earnings as dividends on outstanding common stock issued by the company. The account shall be subdivided for each class of stock.

**9600** **Provision for Income Tax**
This account includes the amount of federal taxes on income properly accruable during the period covered by the income statement to meet the actual liability for such taxes. Concurrently, credits for tax accruals shall be made to account 4400 Income Taxes Payable - Current, and as the exact amount of taxes becomes known, the current tax accruals shall be adjusted accordingly to reflect the actual taxes payable chargeable to utility operations.

# APPENDIX H

## FERC Electric Plant Instructions

[Code of Federal Regulations]
[Title 18, Volume 1, Parts 1 to 399]
[Revised as of April 1, 1999]
From the U.S. Government Printing Office via GPO Access
[CITE: 18CFR]

[Page 291-304]

CHAPTER I--FEDERAL ENERGY REGULATORY COMMISSION, DEPARTMENT OF ENERGY

## Electric Plant Instructions

*1. Classification of electric plant at effective date of system of accounts (Major utilities).*

A. The electric plant accounts provided herein are the same as those contained in the prior system of accounts except for inclusion of accounts for nuclear production plant and some changes in classification in the general equipment accounts. Except for these changes, the balances in the various plant accounts, as determined under the prior system of accounts, should be carried forward. Any remaining balance of plant which has not yet been classified, pursuant to the requirements of the prior system, shall be classified in accordance with the following instructions.

B. The cost to the utility of its unclassified plant shall be ascertained by analysis of the utility's records. Adjustments shall not be made to record in utility plant accounts amounts previously charged to operating expenses or to income deductions in accordance with the uniform system of accounts in effect at the time or in accordance with the discretion of management as exercised under a uniform system of accounts, or under accounting practices previously followed.

C. The detailed electric plant accounts (301 to 399, inclusive) shall be



stated on the basis of cost to the utility of plant constructed by it and the original cost, estimated if not known, of plant acquired as an operating unit or system. The difference between the original cost, as above, and the cost to the utility of electric plant after giving effect to any accumulated provision for depreciation or amortization shall be recorded in account 114, Electric Plant Acquisition Adjustments. The original cost of electric plant shall be determined by analysis of the utility's records or those of the predecessor or vendor companies with respect to electric plant previously acquired as operating units or systems and the difference between the original cost so determined, less accumulated provisions for depreciation and amortization and the cost to the utility with necessary adjustments for retirements from the date of acquisition, shall be entered in account 114, Electric Plant Acquisition Adjustments. Any difference between the cost of electric plant and its book cost, when not properly includible in other accounts, shall be recorded in account 116, Other Electric Plant Adjustments.

D. Plant acquired by lease which qualifies as capital lease property under General Instruction 19. Criteria for Classifying Leases, shall be recorded in Account 101.1, Property under Capital Leases, or Account 120.6, Nuclear Fuel under Capital Leases, as appropriate.

2. *Electric Plant To Be Recorded at Cost.*

A. All amounts included in the accounts for electric plant acquired as an operating unit or system, except as otherwise provided in the texts of the intangible plant accounts, shall be stated at the cost incurred by the person who first devoted the property to utility service. All other electric plant shall be included in the accounts at the cost incurred by the utility, except for property acquired by lease which qualifies as capital lease property under General Instruction 19. Criteria for Classifying Leases, and is recorded in Account 101.1, Property under Capital Leases, or Account 120.6, Nuclear Fuel under Capital Leases. Where the term cost is used in the detailed plant accounts, it shall have the meaning stated in this paragraph.

B. When the consideration given for property is other than cash, the value of such consideration shall be determined on a cash basis (see, however, definition 9). In the entry recording such transition, the actual consideration shall be described with sufficient particularity to identify it. The utility shall be prepared to furnish the Commission the particulars of its determination of the cash value of the consideration if other than cash.

C. When property is purchased under a plan involving deferred payments, no charge shall be made to the electric plant accounts for interest, insurance, or other expenditures occasioned solely by such form of payment.

D. The electric plant accounts shall not include the cost or other value of electric plant contributed to the company. Contributions in the form of money or its equivalent toward the construction of electric plant shall be credited to accounts charged with the cost of such construction. Plant constructed from contributions of cash or its equivalent shall be shown as a reduction to gross plant constructed when assembling cost data in work orders for posting to plant ledgers of accounts. The accumulated gross costs of plant accumulated in the work order shall be recorded as a debit in the plant ledger of accounts along with the related amount of contributions concurrently be recorded as a credit.

*3. Components of construction cost.*

A. For Major utilities, the cost of construction properly includible in the electric plant accounts shall include, where applicable, the direct and overhead cost as listed and defined hereunder:

(1) *Contract work* includes amounts paid for work performed under contract by other companies, firms, or individuals, costs incident to the award of such contracts, and the inspection of such work.

(2) *Labor* includes the pay and expenses of employees of the utility engaged on construction work, and related workmen's compensation insurance, payroll taxes and similar items of expense. It does not include the pay and expenses of employees which are



distributed to construction through clearing accounts nor the pay and expenses included in other items hereunder.

(3) *Materials and supplies* includes the purchase price at the point of free delivery plus customs duties, excise taxes, the cost of inspection, loading and transportation, the related stores expenses, and the cost of fabricated materials from the utility's shop. In determining the cost of materials and supplies used for construction, proper allowance shall be made for unused materials and supplies, for materials recovered from temporary structures used in performing the work involved, and for discounts allowed and realized in the purchase of materials and supplies.

Note: The cost of individual items of equipment of small value (for example, $500 or less) or of short life, including small portable tools and implements, shall not be charged to utility plant accounts unless the correctness of the accounting therefor is verified by current inventories. The cost shall be charged to the appropriate operating expense or clearing accounts, according to the use of such items, or, if such items are consumed directly in construction work, the cost shall be included as part of the cost of the construction

(4) *Transportation* includes the cost of transporting employees, materials and supplies, tools, purchased equipment, and other work equipment (when not under own power) to and from points of construction. It includes amounts paid to others as well as the cost of operating the utility's own transportation equipment. (See item 5 following.)

(5) *Special machine service* includes the cost of labor (optional), materials and supplies, depreciation, and other expenses incurred in the maintenance, operation and use of special machines, such as steam shovels, pile drivers, derricks, ditchers, scrapers, material unloaders, and other labor saving machines; also expenditures for rental, maintenance and operation of machines of others. It does not include the cost of small tools and other individual items of small value or short life which are included in the cost of materials and supplies. (See item 3, above.) When a particular construction job requires the use for an extended period of time of special machines, transportation or other equipment, the net book cost thereof, less the appraised or salvage value at time of release from the job, shall be included in the cost of construction.

(6) *Shop service* includes the proportion of the expense of the utility's shop department assignable to construction work except that the cost of fabricated materials from the utility's shop shall be included in materials and supplies.

(7) *Protection* includes the cost of protecting the utility's property from fire or other casualties and the cost of preventing damages to others, or to the property of others, including payments for discovery or extinguishment of fires, cost of apprehending and prosecuting incendiaries, witness fees in relation thereto, amounts paid to municipalities and others for fire protection, and other analogous items of expenditures in connection with construction work.

(8) *Injuries and damages* includes expenditures or losses in

connection with construction work on account of injuries to persons and damages to the property of others; also the cost of investigation of and defense against actions for such injuries and damages. Insurance recovered or recoverable on account of compensation paid for injuries to persons incident to construction shall be credited to the account or accounts to which such compensation is charged Insurance recovered or recoverable on account of property damages incident to construction shall be credited to the account or accounts charged with the cost of the damages.

(9) *Privileges and permits* includes payments for and expenses incurred in securing temporary privileges, permits or rights in connection with construction work, such as for the use of private or public property, streets, or highways, but it does not include rents, or amounts chargeable as franchises and consents for which see account 302, Franchises and Consents.

(10) *Rents* includes amounts paid for the use of construction quarters and office space occupied by construction forces and amounts properly includible in construction costs for such facilities jointly used.

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(11) *Engineering and supervision* includes the portion of the pay and expenses of engineers, surveyors, draftsmen, inspectors, superintendents and their assistants applicable to construction work.

(12) *General administration capitalized* includes the portion of the pay and expenses of the general officers and administrative and general expenses applicable to construction work.

(13) *Engineering services* includes amounts paid to other companies, firms, or individuals engaged by the utility to plan, design, prepare estimates, supervise, inspect, or give general advice and assistance in connection with construction work.

(14) *Insurance* includes premiums paid or amounts provided or reserved as self-insurance for the protection against loss and damages in connection with construction, by fire or other casualty injuries to or death of persons other than employees, damages to property of others, defalcation of employees and agents, and the nonperformance of

contractual obligations of others. It does not include workmen's compensation or similar insurance on employees included as labor in item 2, above.

(15) *Law expenditures* includes the general law expenditures incurred in connection with construction and the court and legal costs directly related thereto, other than law expenses included in protection, item 7, and in injuries and damages, item 8.

(16) *Taxes* includes taxes on physical property (including land) during the period of construction and other taxes properly includible in construction costs before the facilities become available for service.

(17) *Allowance for funds used during construction* (Major and Nonmajor Utilities) includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used, not to exceed, without prior approval of the Commission, allowances computed in accordance with the formula prescribed in paragraph (a) of this subparagraph. No allowance for funds used during construction charges shall be included in these accounts upon expenditures for construction projects which have been abandoned.

(a) The formula and elements for the computation of the allowance for funds used during construction shall be:

$$Ai=s(S/W)+d(D/D+P+C)(1-S/W)$$
$$Ae=[1-S/W][p(P/D+P+C)+c(C/D+P+C)]$$

Ai=Gross allowance for borrowed funds used during construction rate.
Ae=Allowance for other funds used during construction rate.
S=Average short-term debt.
s=Short-term debt interest rate.
D=Long-term debt.
d=Long-term debt interest rate.
P=Preferred stock.
p=Preferred stock cost rate.
C=Common equity.
c=Common equity cost rate.
W=Average balance in construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment and fabrication.

(b) The rates shall be determined annually. The balances for long-term debt, preferred stock and common equity shall be the actual book balances as of the end of the prior year. The cost rates for long-term debt and preferred stock shall be the weighted average cost determined in the manner indicated in Sec. 35.13 of the Commission's Regulations Under the Federal Power Act. The cost rate for common equity shall be the rate granted common equity in the last rate proceeding before the ratemaking body having primary rate jurisdictions. If such cost rate is not available, the average rate actually earned during the preceding three years shall be used. The short-term debt balances and related cost and the average balance for construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment, and fabrication shall be estimated for the current year with appropriate adjustments as actual data becomes available.

Note: When a part only of a plant or project is placed in operation or is completed and ready for service but the construction work as a whole is incomplete, that part of the cost of the property placed in operation or ready for service, shall be treated as Electric Plant in Service and allowance for funds used during construction thereon as a charge to construction shall cease. Allowance for funds used during construction on that part of the cost of the plant which is incomplete



may be continued as a charge to construction until such time as it is placed in operation or is ready for service, except as limited in item 17, above.

(18) *Earnings and expenses during construction*. The earnings and expenses during construction shall constitute a component of construction costs.

(a) The earnings shall include revenues received or earned for power produced by generating plants during the construction period and sold or used by the utility. Where such power is sold to an independent purchaser before intermingling with power generated by other plants, the credit shall consist of the selling price of the energy. Where the power generated by a plant under construction is delivered to the utility's electric system for distribution and sale, or is delivered to an associated company, or is delivered to and used by the utility for purposes other than distribution and sale (for manufacturing or industrial use, for example), the credit shall be the fair value of the energy so delivered. The revenues shall also include rentals for lands, buildings etc., and miscellaneous receipts not properly includible in other accounts.

(b) The expenses shall consist of the cost of operating the power plant, and other costs incident to the production and delivery of the power for which construction is credited under paragraph (a), above, including the cost of repairs and other expenses of operating and maintaining lands, buildings, and other property, and other miscellaneous and like expenses not properly includible in other accounts.

(19) *Training costs* (Major and Nonmajor Utilities). When it is necessary that employees be trained to operate or maintain plant facilities that are being constructed and such facilities are not conventional in nature, or are new to the company's operations, these costs may be capitalized as a component of construction cost. Once plant is placed in service, the capitalization of training costs shall cease and subsequent training costs shall be expensed. (See Operating Expense Instruction 4.)

(20) *Studies* includes the costs of studies such as nuclear operational, safety, or seismic studies or environmental studies mandated by regulatory bodies relative to plant under construction. Studies relative to facilities in service shall be charged to account 183, Preliminary Survey and Investigation Charges.

B. For Nonmajor utilities, the cost of construction of property chargeable to the electric plant accounts shall include, where applicable, the cost of labor; materials and supplies; transportation; work done by others for the utility; injuries and damages incurred in construction work; privileges and permits; special machine service; allowance for funds used during construction, not to exceed without prior approval of the Commission, amounts computed in accordance with the formula prescribed in paragraph (a) of paragraph (17) of this Instruction; training costs; and such portion of general engineering, administrative salaries and expenses, insurance, taxes, and other analogous items as may be properly includable in construction costs. (See Operating Expense Instruction 4.) The rates and balances of short and long-term debt, preferred stock, common equity and construction work in progress shall be determined as prescribed in paragraph (b) of paragraph (17) of this Instruction.

4. *Overhead Construction Costs*.

A. All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired.

B. As far as practicable, the determination of pay roll charges includible in construction overheads shall be based on time card distributions thereof. Where this procedure is impractical,



special studies shall be made periodically of the time of supervisory employees devoted to construction activities to the end that only such overhead costs as have a definite relation to construction shall be capitalized. The addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted.

C. For Major utilities, the records supporting the entries for overhead construction costs shall be so kept as to show the total amount of each overhead for each year, the nature and amount of each overhead expenditure charged to each construction work order and to each electric plant account, and the bases of distribution of such costs.

*5. Electric Plant Purchased or Sold.*

A. When electric plant constituting an operating unit or system is acquired by purchase, merger, consolidation, liquidation, or otherwise, after the effective date of this system of accounts, the costs of acquisition, including expenses incidental thereto properly includible in electric plant, shall be charged to account 102, Electric Plant Purchased or Sold.

B. The accounting for the acquisition shall then be completed as follows:

(1) The original cost of plant, estimated if not known, shall be credited to account 102, Electric Plant Purchased or Sold, and concurrently charged to the appropriate electric plant in service accounts and to account 104, Electric Plant Leased to Others, account 105, Electric Plant Held for Future Use, and account 107, Construction

Work in Progress--Electric, as appropriate.
(2) The depreciation and amortization applicable to the original cost of the properties purchased shall be charged to account 102, Electric Plant Purchased or Sold, and concurrently credited to the appropriate account for accumulated provision for depreciation or amortization.
(3) The cost to the utility of any property includible in account 121, Nonutility Property, shall be transferred thereto.
(4) The amount remaining in account 102, Electric Plant Purchased or Sold, shall then be closed to account 114, Electric Plant Acquisition Adjustments.
C. If property acquired in the purchase of an operating unit or system is in such physical condition when acquired that it is necessary substantially to rehabilitate it in order to bring the property up to the standards of the utility, the cost of such work, except replacements, shall be accounted for as a part of the purchase price of the property.
D. When any property acquired as an operating unit or system includes duplicate or other plant which will be retired by the accounting utility in the reconstruction of the acquired property or its consolidation with previously owned property, the proposed accounting for such property shall be presented to the Commission.
E. In connection with the acquisition of electric plant constituting an operating unit or system, the utility shall procure, if possible, all existing records relating to the property acquired, or certified copies thereof, and shall preserve such records in conformity with regulations or practices governing the preservation of records of its own construction.
F. When electric plant constituting an operating unit or system is sold, conveyed, or transferred to another by sale, merger, consolidation, or otherwise, the book cost of the property sold or transferred to another shall be credited to the appropriate utility plant accounts, including amounts carried in account 114, Electric Plant Acquisition Adjustments. The amounts (estimated if not known) carried with respect thereto in the accounts for accumulated provision for depreciation and amortization and in account 252, Customer Advances for Construction, shall be charged to such accounts and contra entries made to account 102, Electric Plant Purchased or Sold. Unless otherwise ordered by the Commission, the difference, if any, between (1) the net amount of debits and credits and (2) the consideration received for the property (less commissions and other expenses of making the sale) shall be included in account 421.1. Gain on Disposition of Property, or

account 421.2, Loss on Disposition of Property. (See



account 102, Electric Plant Purchased or Sold.)

Note: In cases where existing utilities merge or consolidate because of financial or operating reasons or statutory requirements rather than as a means of transferring title of purchased properties to a new owner, the accounts of the constituent utilities, with the approval of the Commission, may be combined. In the event original cost has not been determined, the resulting utility shall proceed to determine such cost as outlined herein.

*6. Expenditures on Leased Property*.

A. The cost of substantial initial improvements (including repairs, rear-rangements, additions, and betterments) made in the course of preparing for utility service property leased for a period of more than one year, and the cost of subsequent substantial additions, replacements, or betterments to such property, shall be charged to the electric plant account appropriate for the class of property leased. If the service life of the improvements is terminable by action of the lease, the cost, less net salvage, of the improvements shall be spread over the life of the lease by charges to account 404, Amortization of Limited-Term Electric Plant. However, if the service life is not terminated by action of the lease but by depreciation proper, the cost of the improvements, less net salvage, shall be accounted for as depreciable plant. The provisions of this paragraph are applicable to property leased under either capital leases or operating leases.

B. If improvements made to property leased for a period of more than one year are of relatively minor cost, or if the lease is for a period of not more than one year, the cost of the improvements shall be charged to the account in which the rent is included, either directly or by amortization thereof.

*7. Land and Land Rights*.

A. The accounts for land and land rights shall include the cost of land owned in fee by the utility and rights. Interests, and privileges held by the utility in land owned by others, such as leaseholds, easements, water and water power rights, diversion rights, submersion rights, rights-of-way, and other like interests in land. Do not include in the accounts for land and land rights and rights-of-way costs incurred in connection with first clearing and grading of land and rights-of-way and the damage costs associated with the construction and installation of plant. Such costs shall be included in the appropriate plant accounts directly benefited.

B. Where special assessments for public improvements provide for deferred payments, the full amount of the assessments shall be charged to the appropriate land account and the unpaid balance shall be carried in an appropriate liability account. Interest on unpaid balances shall be charged to the appropriate interest account. If any part of the cost of public improvements is included in the general tax levy, the amount thereof shall be charged to the appropriate tax account.

C. The net profit from the sale of timber, cord wood, sand, gravel, other resources or other property acquired with the rights-of-way or other lands shall be credited to the appropriate plant account to which related. Where land is held for a considerable period of time and timber and other natural resources on the land at the time of purchase increases in value, the net profit (after giving effect to the cost of the natural resources) from the sales of timber or its products or other natural resources shall be credited to the appropriate utility operating income account when such land has been recorded in account 105, Electric Plant Held for Future Use or classified as plant in service, otherwise to account 421, Miscellaneous Nonoperating Income.

D. Separate entries shall be made for the acquisition, transfer, or retirement of each parcel of land, and each land right (except rights of way for distribution lines), or water right, having a life of more than one year. A record shall be maintained showing the nature of ownership, full legal description, area, map reference, purpose for which used, city, county, and tax district on which situated, from whom purchased or to whom sold, payment given or received, other costs, contract date and number, date of recording of deed, and book and page of record. Entries transferring or retiring land or land rights shall refer



to the original entry recording its acquisition.

E. Any difference between the amount received from the sale of land or land rights, less agents' commissions and other costs incident to the sale, and the book cost of such land or rights, shall be included in account 411.6, Gains from Disposition of Utility Plant, or 411.7, Losses from Disposition of Utility Plant when such property has been recorded in account 105, Electric Plant Held for Future Use, otherwise to account 421.1, Gain on Disposition of Property or 421.2, Loss on Disposition of Property, as appropriate, unless a reserve therefor has been authorized and provided. Appropriate adjustments of the accounts shall be made with respect to any structures or improvements located on land sold.

F. The cost of buildings and other improvements (other than public improvements) shall not be included in the land accounts. If at the time of acquisition of an interest in land such interest extends to buildings or other improvements (other than public improvements) which are then devoted to utility operations, the land and improvements shall be separately appraised and the cost allocated to land and buildings or improvements on the basis of the appraisals. If the improvements are removed or wrecked without being used in operations, the cost of removing or wrecking shall be charged and the salvage credited to the account in which the cost of the land is recorded.

G. When the purchase of land for electric operations requires the purchase of more land than needed for such purposes, the charge to the specific land account shall be based upon the cost of the land purchased, less the fair market value of that portion of the land which is not to be used in utility operations. The portion of the cost measured by the fair market value of the land not to be used shall be included in account 105, Electric Plant Held for Future Use, or account 121, Nonutility Property, as appropriate.

H. Provisions shall be made for amortizing amounts carried in the accounts for limited-term interests in land so as to apportion equitably the cost of each interest over the life thereof. (For Major utilities, see account 111, Accumulated Provision for Amortization of Electric Plant Utility, and account 404, Amortization of Limited-Term Electric Plant. For Nonmajor utilities, see account 404.)

I. The items of cost to be included in the accounts for land and land rights are as follows:

1. Bulkheads, buried, not requiring maintenance or replacement.
2. Cost, first, of acquisition including mortgages and other liens assumed (but not subsequent interest thereon).
3. [Reserved]
4. Condemnation proceedings, including court and counsel costs.
5. Consents and abutting damages, payment for.
6. Conveyancers' and notaries' fees.
7. Fees, commissions, and salaries to brokers, agents and others in connection with the acquisition of the land or land rights.
8. [Reserved]

9. Leases, cost of voiding upon purchase to secure possession of land.

10. Removing, relocating, or reconstructing, property of others, such as buildings, highways, railroads, bridges, cemeteries, churches, telephone and power lines, etc., in order to acquire quiet possession.

11. Retaining walls unless identified with structures.

12. Special assessments levied by public authorities for public improvements on the basis of benefits for new roads, new bridges, new sewers, new curbing, new pavements, and other public improvements, but not taxes levied to provide for the maintenance of such improvements.

13. Surveys in connection with the acquisition, but not amounts paid for topographical surveys and maps where such costs are attributable to structures or plant equipment erected or to be erected or installed on such land.

14. Taxes assumed, accrued to date of transfer of title.

15. Title, examining, clearing, insuring and registering in connection with the acquisition and defending against claims relating to the period prior to the acquisition.

16. Appraisals prior to closing title.

17. Cost of dealing with distributees or legatees residing outside of the state or county, such as recording power of attorney, recording will or exemplification of will, recording satisfaction of state tax.

18. Filing satisfaction of mortgage.

19. Documentary stamps.

20. Photographs of property at acquisition.

21. Fees and expenses incurred in the acquisition of water rights and grants.

22. Cost of fill to extend bulkhead line over land under water, where riparian rights are



held, which is not occasioned by the erection of a structure.

23. Sidewalks and curbs constructed by the utility on public property.

24. Labor and expenses in connection with securing rights of way, where performed by company employees and company agents.

*8. Structures and Improvements.*

A. The accounts for structures and improvements shall include the cost of all buildings and facilities to house, support, or safeguard property or persons, including all fixtures permanently attached to and made a part of buildings and which cannot be removed therefrom without cutting into the walls, ceilings, or floors, or without in some way impairing the buildings, and improvements of a permanent character on or to land. Also include those costs incurred in connection with the first clearing and grading of land and rights-of-way and the damage costs associated with construction and installation of plant.

B. The cost of specially provided foundations not intended to outlast the machinery or apparatus for which provided, and the cost of angle irons, castings, etc., installed at the base of an item of equipment, shall be charged to the same account as the cost of the machinery, apparatus, or equipment.

C. Minor buildings and structures, such as valve towers, patrolmen's towers, telephone stations, fish and wildlife, and recreation facilities, etc., which are used directly in connection with or form a part of a reservoir, dam, waterway, etc., shall be considered a part of the facility in connection with which constructed or operated and the cost thereof accounted for accordingly.

D. Where furnaces and boilers are used primarily for furnishing steam for some particular department and only incidentally for furnishing steam for heating a building and operating the equipment therein, the entire cost of such furnaces and boilers shall be charged to the appropriate plant account, and no part to the building account.

E. Where the structure of a dam forms also the foundation of the power plant building, such foundation shall be considered a part of the dam.

F. The cost of disposing of materials excavated in connection with construction of structures shall be considered as a part of the cost of such work, except as follows: (a) When such material is used for filling, the cost of loading, hauling, and dumping shall be equitably apportioned between the work in connection with which the removal occurs and the work in connection with which the material is used; (b) when such material is sold, the net amount realized from such sales shall be credited to the work in connection with which the removal occurs. If the amount realized from the sale of excavated materials exceeds the removal costs and the costs in connection with the sale, the excess shall be credited to the land account in which the site is carried.

G. Lighting or other fixtures temporarily attached to buildings for purposes of display or demonstration shall not be included in the cost of the building but in the appropriate equipment account.

H. The items of cost to be included in the accounts for structures and improvements are as follows:

1. Architects' plans and specifications including supervision.
2. Ash pits (when located within the building). (Major Utilities)
3. Athletic field structures and improvements.
4. Boilers, furnaces, piping, wiring, fixtures, and machinery for heating, lighting, signaling, ventilating, and air-conditioning systems, plumbing, vacuum cleaning systems, incinerator and smoke pipe, flues, etc.
5. Bulkheads, including dredging, riprap fill, piling, decking, concrete, fenders, etc., when exposed and subject to maintenance and replacement.
6. Chimneys (Major Utilities).
7. Coal bins and bunkers.
8. Commissions and fees to brokers, agents, architects, and others.
9. Conduit (not to be removed) with its contents.
10. Damages to abutting property during construction.
11. Docks (Major Utilities).
12. Door checks and door stops (Major Utilities).
13. Drainage and sewerage systems.
14. Elevators, cranes, hoists, etc., and the machinery for operating them.
15. Excavation, including shoring, bracing, bridging, refill and disposal of excess excavated material, cofferdams around foundation, pumping water from cofferdams during construction, and test borings.



16. Fences and fence curbs (not including protective fences isolating items of equipment, which shall be charged to the appropriate equipment account).
17. Fire protection systems when forming a part of a structure.
18. Flagpole (Major Utilities).
19. Floor covering (permanently attached) (Major Utilities).
20. Foundations and piers for machinery, constructed as a permanent part of a building or other item listed herein.
21. Grading and clearing when directly occasioned by the building of a structure.
22. Intrasite communication system, poles, pole fixtures, wires, and cables.
23. Landscaping, lawns, shrubbery, etc.
24. Leases, voiding upon purchase to secure possession of structures.
25. Leased property, expenditures on.

26. Lighting fixtures and outside lighting system.
27. Mailchutes when part of a building (Major Utilities).
28. Marquee, permanently attached to building (Major Utilities).
29. Painting, first cost.
30. Permanent paving, concrete, brick, flagstone, asphalt, etc., within the property lines.
31. Partitions, including movable (Major Utilities).
32. Permits and privileges.
33. Platforms, railings, and gratings when constructed as a part of a structure.
34. Power boards for services to a building (Major Utilities).
35. Refrigerating systems for general use (Major Utilities).
36. Retaining walls except when identified with land.
37. Roadways, railroads, bridges, and trestles intrasite except railroads provided for in equipment accounts.
38. Roofs (Major Utilities).
39. Scales, connected to and forming a part of a structure (Major Utilities).
40. Screens (Major Utilities).
41. Sewer systems, for general use (Major Utilities).
42. Sidewalks, culverts, curbs and streets constructed by the utility on its property (Major Utilities).
43. Sprinkling systems (Major Utilities).
44. Sump pumps and pits (Major Utilities).
45. Stacks--brick, steel, or concrete, when set on foundation forming part of general foundation and steelwork of a building.
46. Steel inspection during construction (Major Utilities).
47. Storage facilities constituting a part of a building.
48. Storm doors and windows (Major Utilities).
49. Subways, areaways, and tunnels, directly connected to and forming part of a structure.
50. Tanks, constructed as part of a building or as a distinct structural unit.
51. Temporary heating during construction (net cost) (Major Utilities).
52. Temporary water connection during construction (net cost) (Major Utilities).
53. Temporary shanties and other facilities used during construction (net cost)
54. Topographical maps (Major Utilities).
55. Tunnels, intake and discharge, when constructed as part of a structure, including sluice gates, and those constructed to house mains.

56. Vaults constructed as part of a building.
57. Watchmen's sheds and clock systems (net cost when used during construction only) (Major Utilities).
58. Water basins or reservoirs.
59. Water front improvements (Major Utilities).
60. Water meters and supply system for a building or for general company purposes (Major Utilities).
61. Water supply piping, hydrants and wells (Major Utilities).
62. Wharves.
63. Window shades and ventilators (Major Utilities).
64. Yard drainage system (Major Utilities).
65. Yard lighting system (Major Utilities).
66. Yard surfacing, gravel, concrete, or oil. (First cost only.) (Major Utilities)

Note: Structures and Improvements accounts shall be credited with the cost of coal bunkers, stacks, foundations, subways, tunnels, etc., the use of which has terminated with the removal of the equipment with which they are associated even though they have not been physically removed.

*9. Equipment*.

A. The cost of equipment chargeable to the electric plant accounts, unless otherwise indicated in the text of an equipment account, includes the net purchase price thereof, sales taxes, investigation and inspection expenses necessary to such purchase, expenses of transportation when borne by the utility, labor employed, materials and supplies consumed, and expenses incurred by the utility in unloading and placing the equipment in readiness to operate. Also include those costs incurred in connection with the first clearing and grading of land and rights-of-way and the damage costs associated with construction and installation of plant.

B. Exclude from equipment accounts hand and other portable tools, which are likely to be lost or stolen or which have relatively small value (for example, $500 or less) or short life, unless



the correctness of the accounting therefor as electric plant is verified by current inventories. Special tools acquired and included in the purchase price of equipment shall be included in the appropriate plant account. Portable drills and similar tool equipment when used in connection with the operation and maintenance of a particular plant or department, such as production, transmission, distribution, etc., or in stores, shall be charged to the plant account appropriate for their use.

C. The equipment accounts shall include angle irons and similar items which are installed at the base of an item of equipment, but piers and foundations which are designed to be as permanent as the buildings which house the equipment, or which are constructed as a part of the building and which cannot be removed without cutting into the walls, ceilings or floors or without in some way impairing the building, shall be included in the building accounts.

D. The equipment accounts shall include the necessary costs of testing or running a plant or parts thereof during an experimental or test period prior to such plant becoming ready for or placed in service. In the case of Nonmajor utilities, the utility shall pay the fee prescribed in part 381 of this chapter and shall furnish the Commission with full particulars of and justification for any test or experimental run extending beyond a period of 30 days. In the case of Major utilities, the utility shall furnish the Commission with full particulars of and justification for any test or experimental run extending beyond a period of 120 days for nuclear plant, and a period of 90 days for all other plant. Such particulars shall include a detailed operational and downtime log showing days of production, gross kilowatts generated by hourly increments, types, and periods of outages by hours with explanation thereof, beginning with the first date the equipment was either tested or synchronized on the line to the end of the test period.

E. The cost of efficiency or other tests made subsequent to the date equipment becomes available for service shall be charged to the appropriate expense accounts, except that tests to determine whether equipment meets the specifications and requirements as to efficiency, performance, etc., guaranteed by manufacturers, made after operations have commenced and within the period specified in the agreement or contract of purchase may be charged to the appropriate electric plant account.

*10. Additions and Retirements of Electric Plant.*

A. For the purpose of avoiding undue refinement in accounting for additions to and retirements and replacements of electric plant, all property will be considered as consisting of (1) retirement units and (2) minor items of property. Each utility shall maintain a written property units listing for use in accounting for additions and retirements of electric plant and apply the listing consistently.

B. The addition and retirement of retirement units shall be accounted for as follows:

(1) When a retirement unit is added to electric plant, the cost thereof shall be added to the appropriate electric plant account, except that when units are acquired in the acquisition of any electric plant constituting an operating system, they shall be accounted for as provided in electric plant instruction 5.

(2) When a retirement unit is retired from electric plant, with or without replacement, the book cost thereof shall be credited to the electric plant account in which it is included, determined in the manner set forth in paragraph D, below. If the retirement unit is of a depreciable class, the book cost of the unit retired and credited to electric plant shall be charged to the accumulated provision for depreciation applicable to such property. The cost of removal and the salvage shall be charged or credited, as appropriate, to such depreciation account.

C. The addition and retirement of minor items of property shall be accounted for as follows:

(1) When a minor item of property which did not previously exist is added to plant, the cost thereof shall be accounted for in the same manner as for the addition of a retirement unit, as set forth in paragraph B(1), above, if a substantial addition results, otherwise



the charge shall be to the appropriate maintenance expense account.

(2) When a minor item of property is retired and not replaced, the book cost thereof shall be credited to the electric plant account in which it is included; and, in the event the minor item is a part of depreciable plant, the account for accumulated provision for depreciation shall be charged with the book cost and cost of removal and credited with the salvage. If, however, the book cost of the minor item retired and not replaced has been or will be accounted for by its inclusion in the retirement unit of which it is a part when such unit is retired, no separate credit to the property account is required when such minor item is retired.

(3) When a minor item of depreciable property is replaced independently of the retirement unit of which it is a part, the cost of replacement shall be charged to the maintenance account appropriate for the item, except that if the replacement effects a substantial betterment (the primary aim of which is to make the property affected

more useful, more efficient, of greater durability, or of greater capacity), the excess cost of the replacement over the estimated cost at current prices of replacing without betterment shall be charged to the appropriate electric plant account.

D. The book cost of electric plant retired shall be the amount at which such property is included in the electric plant accounts, including all components of construction costs. The book cost shall be determined from the utility's records and if this cannot be done it shall be estimated. Utilities must furnish the particulars of such estimates to the Commission, if requested. When it is impracticable to determine the book cost of each unit, due to the relatively large number or small cost thereof, an appropriate average book cost of the units, with due allowance for any differences in size and character, shall be used as the book cost of the units retired.

E. The book cost of land retired shall be credited to the appropriate land account. If the land is sold, the difference between the book cost (less any accumulated provision for depreciation or amortization therefore which has been authorized and provided) and the sale price of the land (less commissions and other expenses of making the sale) shall be recorded in account 411.6, Gains from Disposition of Utility Plant, or 411.7, Losses from Disposition of Utility Plant when the property has been recorded in account 105, Electric Plant Held for Future Use, otherwise to accounts 421.1, Gain on Disposition of Property or 421.2, Loss on Disposition of Property, as appropriate. If the land is not used in utility service but is retained by the utility, the book cost shall be charged to account 105, Electric Plant Held for Future Use, or account 121, Nonutility Property, as appropriate.

F. The book cost less net salvage of depreciable electric plant retired shall be charged in its entirety to account 108. Accumulated Provision for Depreciation of Electric Plant in Service (Account 110, Accumulated Provision for Depreciation and Amortization of Electric Utility Plant, in the case of Nonmajor utilities). Any amounts which, by approval or order of the Commission, are charged to account 182.1, Extraordinary Property Losses, shall be credited to account 108 (Account 110 for Nonmajor utilities).

G. In the case of Major utilities, the accounting for the retirement of amounts included in account 302, Franchises and Consents, and account 303, Miscellaneous Intangible Plant, and the items of limited-term interest in land included in the accounts for land and land rights, shall be as provided for in the text of account 111. Accumulated Provision for Amortization of Electric Plant in Service, account 404, Amortization of Limited-Term Electric Plant, and account 405, Amortization of Other Electric Plant.

*11. Work Order and Property Record System Required.*

A. Each utility shall record all construction and retirements of electric plant by means of work orders or job orders. Separate work orders may be opened for additions to and retirements of electric plant or the retirements may be included with the construction work order, provided, however, that all items relating to the retirements shall be kept separate from those relating to construction and provided, further,

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that any maintenance costs involved in the work shall likewise be segregated.

B. Each utility shall keep its work order system so as to show the nature of each addition to or retirement of electric plant, the total cost thereof, the source or sources of costs, and the electric plant account or accounts to which charged or credited. Work orders covering jobs of short duration may be cleared monthly.

C. In the case of Major utilities, each utility shall maintain records in which, for each plant account, the amounts of the annual additions and retirements are classified so as to show the number and cost of the various record units or retirement units.

*12. Transfers of Property.*

When property is transferred from one electric plant account to another, from one utility department to another, such as from electric to gas, from one operating division or area to another, to or from accounts 101, Electric Plant in Service, 104. Electric Plant Leased to Others, 105. Electric Plant Held for Future Use, and 121, Nonutility Property, the transfer shall be recorded by transferring the original cost thereof from the one account, department, or location to the other. Any related amounts carried in the accounts for accumulated provision for depreciation or amortization shall be transferred in accordance with the segregation of such accounts.

*13. Common Utility Plant.*

A. If the utility is engaged in more than one utility service, such as electric, gas, and water, and any of its utility plant is used in common for several utility services or for other purposes to such an extent and in such manner that it is impracticable to segregate it by utility services currently in the accounts, such property, with the approval of the Commission, may be designated and classified as common utility plant.

B. The book amount of utility plant designated as common plant shall be included in account 118, Other Utility Plant, and if applicable in part to the electric department, shall be segregated and accounted for in subaccounts as electric plant is accounted for in accounts 101 to 107, inclusive, and electric plant adjustments in account 116; any amounts classifiable as common plant acquisition adjustments or common plant adjustments shall be subject to disposition as provided in paragraphs C and B of accounts 114 and 116, respectively, for amounts classified in those accounts. The original cost of common utility plant in service shall be classified according to detailed utility plant accounts appropriate for the property.

C. The utility shall be prepared to show at any time and to report to the Commission annually, or more frequently, if required, and by utility plant accounts (301 to 399) the following: (1) The book cost of common utility plant, (2) The allocation of such cost to the respective departments using the common utility plant, and (3) The basis of the allocation.

D. The accumulated provision for depreciation and amortization of the utility shall be segregated so as to show the amount applicable to the property classified as common utility plant.

E. The expenses of operation, maintenance, rents, depreciation and amortization of common utility plant shall be recorded in the accounts prescribed herein, but designated as common expenses, and the allocation of such expenses to the departments using the common utility plant shall be supported in such manner as to reflect readily the basis of allocation used.

*14. Transmission and Distribution Plant.*

For the purpose of this system of accounts:

A. Transmission system means:

(1) All land, conversion structures, and equipment employed at a primary source of supply (i.e., generating station, or point of receipt in the case of purchased power) to change the voltage or frequency of electricity for the purpose of its more efficient or convenient transmission;

(2) All land, structures, lines, switching and conversion stations,

high tension apparatus, and their control and protective equipment between a generating or receiving point and the entrance to a distribution center or wholesale point; and

(3) All lines and equipment whose primary purpose is to augment, integrate



or tie together the sources of power supply

B. Distribution system means all land, structures, conversion equipment, lines, line transformers, and other facilities employed between the primary source of supply (i.e., generating station, or point of receipt in the case of purchased power) and of delivery to customers, which are not includible in transmission system, as defined in paragraph A, whether or not such land, structures, and facilities are operated as part of a transmission system or as part of a distribution system.

Note: Stations which change electricity from transmission to distribution voltage shall be classified as distribution stations.

C. Where poles or towers support both transmission and distribution conductors, the poles, towers, anchors, guys, and rights of way shall be classified as transmission system. The conductors, crossarms, braces, grounds, tiewire, insulators, etc., shall be classified as transmission or distribution facilities, according to the purpose for which used.

D. Where underground conduit contains both transmission and distribution conductors, the underground conduit and right of way shall be classified as distribution system. The conductors shall be classified as transmission or distribution facilities according to the purpose for which used.

E. Land (other than rights of way) and structures used jointly for transmission and distribution purposes shall be classified as transmission or distribution according to the major use thereof.

*15. Hydraulic production plant (Major Utilities).*

For the purpose of this system of accounts hydraulic production plant means all land and land rights, structures and improvements used in connection with hydraulic power generation, reservoirs dams and waterways, water wheels, turbines, generators, accessory electric equipment, miscellaneous powerplant equipment, roads, railroads, and bridges, and structures and improvements used in connection with fish and wildlife, and recreation.

*16. Nuclear Fuel Records Required (Major Utilities)*.

Each utility shall keep all the necessary records to support the entries to the various nuclear fuel plant accounts classified under ``Assets and Other Debits," Utility Plant 120.1 through 120.6, inclusive, account 518, Nuclear Fuel Expense and account 157, Nuclear Materials Held for Sale. These records shall be so kept as to readily furnish the basis of the computation of the net nuclear fuel costs.

# APPENDIX I

## FERC Electric Plant Accounts

[Code of Federal Regulations]
[Title 18, Volume 1, Parts 1 to 399]
[Revised as of April 1, 1999]
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[Page 337-355]

CHAPTER I--FEDERAL ENERGY REGULATORY COMMISSION, DEPARTMENT OF ENERGY

## Electric Plant Accounts

### 301 Organization.

This account shall include all fees paid to federal or state governments for the privilege of incorporation and expenditures incident to organizing the corporation, partnership, or other enterprise and putting it into readiness to do business.

ITEMS

1. Cost of obtaining certificates authorizing an enterprise to engage in the public-utility business.
2. Fees and expenses for incorporation
3. Fees and expenses for mergers or consolidations.
4. Office expenses incident to organizing the utility.
5. Stock and minute books and corporate seal.

Note A: This account shall not include any discounts upon securities issued or assumed; nor shall it include any costs incident to negotiating loans, selling bonds or other evidences of debt or expenses in connection with the authorization, issuance or sale of capital stock.

Note B: Exclude from this account and include in the appropriate expense account the cost of preparing and filing papers in connection with the extension of the term of incorporation unless the first organization costs have been written off. When charges are made to this account for expenses incurred in mergers, consolidations, or reorganizations, amounts previously included herein or in similar accounts in the books of the companies concerned shall be excluded from this account.

**302 Franchises and consents**.

A. This account shall include amounts paid to the federal government, to a state or to a political subdivision thereof in consideration for franchises, consents, water power licenses, or certificates, running in perpetuity or for a specified term of more than one year, together with necessary and reasonable expenses incident to procuring such franchises, consents, water power licenses, or certificates of permission and approval, including expenses of organizing and merging separate corporations, where statutes require, solely for the purpose of acquiring franchises.

B. If a franchise, consent, water power license or certificate is acquired by assignment, the charge to this account in respect thereof shall not exceed the amount paid therefor by the utility to the assignor, nor shall it exceed the amount paid by the original grantee, plus the expense of acquisition to such grantee. Any excess of the amount actually paid by the utility over the amount above specified shall be charged to account 426.5, Other Deductions.

C. When any franchise has expired, the book cost thereof shall be credited hereto and charged to account 426.5, Other Deductions, or to account 111, Accumulated Provision for Amortization of Electric Utility Plant (for Nonmajor utilities, account 110, Accumulated Provision for Depreciation and Amortization of Electric Plant), as appropriate.

D. Records supporting this account shall be kept so as to show separately the book cost of each franchise or consent.

Note: Annual or other periodic payments under franchises shall not be included herein but in the appropriate operating expense account.

**303 Miscellaneous intangible plant**.

A. This account shall include the cost of patent rights, licenses, privileges, and other intangible property necessary or valuable in the conduct of utility operations and not specifically chargeable to any other account.

B. When any item included in this account is retired or expires, the book cost thereof shall be credited hereto and charged to account 426.5, Other Deductions, or account 111, Accumulated Provision for Amortization of Electric Utility Plant (for Nonmajor utilities, account 110, Accumulated Provision for Depreciation and Amortization of Electric Plant), as appropriate.

C. This account shall be maintained in such a manner that the utility can furnish full information with respect to the amounts included herein.

**310 Land and land rights**.

This account shall include the cost of land and land rights used in connection with steam-power generation. (See electric plant instruction 7.)



**311 Structures and improvements**.

This account shall include the cost in place of structures and improvements used in connection with steam-power generation. (See electric plant instruction 8.)

Note: Include steam production roads and railroads in this account.

**312 Boiler plant equipment**.

This account shall include the cost installed of furnaces, boilers, coal and ash handling and coal preparing equipment, steam and feed water piping, boiler apparatus and accessories used in the production of steam, mercury, or other vapor, to be used primarily for generating electricity.

ITEMS

1. Ash handling equipment, including hoppers, gates, cars, conveyors, hoists, sluicing equipment, including pumps and motors, sluicing water pipe and fittings, sluicing trenches and accessories, etc., except sluices which are a part of a building.
2. Boiler feed system, including feed water heaters, evaporator condensers, heater drain pumps, heater drainers, deaerators, and vent condensers, boiler feed pumps, surge tanks, feed water regulators, feed water measuring equipment, and all associated drives.
3. Boiler plant cranes and hoists and associated drives.
4. Boilers and equipment, including boilers and baffles, economizers, superheaters, soot blowers, foundations and settings, water walls, arches, grates, insulation, blow-down system, drying out of new boilers, also associated motors or other power equipment.

5. Breeching and accessories, including breeching, dampers, soot spouts, hoppers and gates, cinder eliminators, breeching insulation, soot blowers and associated motors.

6. Coal handling and storage equipment, including coal towers, coal lorries, coal cars, locomotives and tracks when devoted principally to the transportation of coal, hoppers, downtakes, unloading and hoisting equipment, skip hoists and conveyors, weighing equipment, magnetic separators, cable ways, housings and supports for coal handling equipment.

7. Draft equipment, including air preheaters and accessories, induced and forced draft fans, air ducts, combustion control mechanisms, and associated motors or other power equipment.

8. Gas-burning equipment, including holders, burner equipment and piping, control equipment, etc.

9. Instruments and devices, including all measuring, indicating, and recording equipment for boiler plant service together with mountings and supports.

10. Lighting systems.

11. Oil-burning equipment, including tanks, heaters, pumps with drive, burner equipment and piping, control equipment, etc.

12. Pulverized fuel equipment, including pulverizers, accessory motors, primary air fans, cyclones and ducts, dryers, pulverized fuel bins, pulverized fuel conveyors and equipment, burners, burner piping, priming equipment, air compressors, motors, etc.

13. Stacks, including foundations and supports, stack steel and ladders, stack brick work, stack concrete, stack lining, stack painting (first), when set on separate foundations, independent of substructure or superstructure of building.

14. Station piping, including pipe, valves, fittings, separators, traps, desuperheaters, hangers, excavation, covering, etc., for station piping system, including all steam, condensate, boiler feed and water supply piping, etc., but not condensing water, plumbing, building heating, oil, gas, air piping or piping specifically provided for in account 313.

15. Stoker or equivalent feeding equipment, including stokers and accessory motors, clinker grinders, fans and motors, etc.

16. Ventilating equipment.

17. Water purification equipment, including softeners and accessories, evaporators and accessories, heat exchangers, filters, tanks for filtered or softened water, pumps, motors, etc.

18. Water-supply systems, including pumps, motors, strainers, raw-water storage tanks, boiler wash pumps, intake and discharge pipes and

tunnels not a part of a building.
19. Wood fuel equipment, including hoppers, fuel hogs and accessories, elevators and conveyors, bins and gates, spouts, measuring equipment and associated drives.

Note: When the system for supplying boiler or condenser water is elaborate, as when it includes a dam, reservoir, canal, pipe line, cooling ponds, or where gas or oil is used as a fuel for producing steam and is supplied through a pipe line system owned by the utility, the cost of such special facilities shall be charged to a subdivision of account 311, Structures and Improvements.

**313 Engines and engine-driven generators**.

This account shall include the cost installed of steam engines, reciprocating or rotary, and their associated auxiliaries; and engine-driven main generators, except turbogenerator units.



ITEMS

1. Air cleaning and cooling apparatus, including blowers, drive equipment, air ducts not a part of building, louvers, pumps, hoods, etc.
2. Belting, shafting, pulleys, reduction gearing, etc.
3. Circulating pumps, including connections between condensers and intake and discharge tunnels.
4. Cooling system, including towers, pumps, tank, and piping.
5. Condensers, including condensate pumps, air and vacuum pumps, ejectors, unloading valves and vacuum breakers, expansion devices, screens, etc.
6. Cranes, hoists, etc., including items wholly identified with items listed herein.
7. Engines, reciprocating or rotary.
8. Fire-extinguishing systems.
9. Foundations and settings, especially constructed for and not expected to outlast the apparatus for which provided.
10. Generators--Main, a.c. or d.c., including field rheostats and connections for self-excited units, and excitation systems when identified with the generating unit.
11. Governors.
12. Lighting systems.

13. Lubricating systems including gauges, filters, tanks, pumps, piping, motors, etc.
14. Mechanical meters, including gauges, recording instruments, sampling and testing equipment.
15. Piping--main exhaust, including connections between generator and condenser and between condenser and hotwell.
16. Piping--main steam, including connections from main throttle valve to turbine inlet.
17. Platforms, railings, steps, gratings, etc., appurtenant to apparatus listed herein.
18. Pressure oil system, including accumulators, pumps, piping, motors, etc.
19. Throttle and inlet valve.
20. Tunnels, intake and discharge, for condenser system, when not a part of a structure.
21. Water screens, motors, etc.

**314 Turbogenerator units**.

This account shall include the cost installed of main turbine-driven units and accessory equipment used in generating electricity by steam.

ITEMS

1. Air cleaning and cooling apparatus, including blowers, drive equipment, air ducts not a part of building, louvers, pumps, hoods, etc.
2. Circulating pumps, including connections between condensers and intake and discharge tunnels.
3. Condensers, including condensate pumps, air and vacuum pumps, ejectors, unloading valves and vacuum breakers, expansion devices, screens, etc.
4. Generator hydrogen, gas piping and detrainment equipment.
5. Cooling system, including towers, pumps, tanks, and piping.
6. Cranes, hoists, etc., including items wholly identified with items listed herein.
7. Excitation system, when identified with main generating units.
8. Fire-extinguishing systems.
9. Foundations and settings, especially constructed for and not expected to outlast the apparatus for which provided.
10. Governors.
11. Lighting systems.
12. Lubricating systems, including gauges, filters, water

separators, tanks, pumps, piping, motors, etc.
13. Mechanical meters, including gauges, recording instruments, sampling and testing equipment.
14. Piping--main exhaust, including connections between turbogenerator and condenser and between condenser and hotwell.
15. Piping--main steam, including connections from main throttle valve to turbine inlet.
16. Platforms, railings, steps, gratings, etc., appurtenant to apparatus listed herein.
17. Pressure oil systems, including accumulators, pumps, piping, motors, etc.
18. Steelwork, specially constructed for apparatus listed herein.
19. Throttle and inlet valve.
20. Tunnels, intake and discharge, for condenser system, when not a part of structure, water screens, etc.
21. Turbogenerators--main, including turbine and generator, field rheostats and electric connections for self-excited units.
22. Water screens, motors, etc.
23. Moisture separator for turbine steam.
24. Turbine lubricating oil (initial charge).

**315 Accessory electric equipment**.

This account shall include the cost installed of auxiliary generating apparatus, conversion equipment, and equipment used primarily in connection with the control and switching of electric energy produced by steam power, and the protection of electric circuits and equipment, except electric motors used to drive equipment included in other accounts. Such motors shall be included in the account in which the equipment with which they are associated is included.

ITEMS

1. Auxiliary generators, including boards, compartments, switching equipment, control



equipment, and connections to auxiliary power bus.
2. Excitation system, including motor, turbine and dual-drive exciter sets and rheostats, storage batteries and charging equipment, circuit breakers, panels and accessories, knife switches and

accessories, surge arresters, instrument shunts, conductors and conduit, special supports for conduit, generator field and exciter switch panels, exciter bus tie panels, generator and exciter rheostats, etc., special housing, protective screens, etc.

3. Generator main connections, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, current transformers, potential transformers, protective relays, isolated panels and equipment, conductors and conduit, special supports for generator main leads grounding switch, etc., special housings, protective screens, etc.

4. Station buses including main, auxiliary, transfer, synchronizing and fault ground buses, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, reactors and accessories, voltage regulators and accessories, compensators, resistors, starting transformers, current transformers, potential transformers, protective relays, storage batteries and charging equipment, isolated panels and equipment, conductors and conduit, special supports, special housings, concrete pads, general station grounding system, special fire-extinguishing system, and test equipment.

5. Station control system, including station switchboards with panel wiring, panels with instruments and control equipment only, panels with switching equipment mounted or mechanically connected, truck-type boards complete, cubicles, station supervisory control boards, generator and exciter signal stands, temperature recording devices, frequency-control equipment, master clocks, watt-hour meters and synchronoscope in the turbine room, station totalizing wattmeter, boiler-room load indicator equipment, storage batteries, panels and charging sets, instrument transformers for supervisory metering, conductors and conduit, special supports for conduit, switchboards, batteries, special housing for batteries, protective screens, doors, etc.

Note A: Do not include in this account transformers and other equipment used for changing the voltage or frequency of electricity for the purposes of transmission or distribution.

Note B: When any item of equipment listed herein is used wholly to furnish power to equipment included in another account, its cost shall be included in such other account.

**316 Miscellaneous power plant equipment**.

This account shall include the cost installed of miscellaneous equipment in and about the steam generating plant devoted to general station use, and which is not properly includible in any of the foregoing steam-power production accounts.

ITEMS

1. Compressed air and vacuum cleaning systems, including tanks, compressors, exhausters, air filters, piping, etc.
2. Cranes and hoisting equipment, including cranes, cars, crane rails, monorails, hoists, etc., with electric and mechanical connections.
3. Fire-extinguishing equipment for general station use.
4. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided.
5. Locomotive cranes not includible elsewhere.
6. Locomotives not includible elsewhere.
7. Marine equipment, including boats, barges, etc.
8. Miscellaneous belts, pulleys, countershafts, etc.
9. Miscellaneous equipment, including atmospheric and weather indicating devices, intrasite communication equipment, laboratory equipment, signal systems, callophones emergency whistles and sirens, fire alarms, insect-control equipment, and other similar equipment.
10. Railway cars not includible elsewhere.
11. Refrigerating systems, including compressors, pumps, cooling coils, etc.
12. Station maintenance equipment, including lathes, shapers, planers, drill presses, hydraulic presses, grinders, etc., with motors, shafting, hangers, pulleys, etc.
13. Ventilating equipment, including items wholly identified with apparatus listed herein.

Note: When any item of equipment listed herein is wholly used in connection with equipment included in another account, its cost shall be included in such other account.

**320 Land and land rights (Major only)**.

This account shall include the cost of land and land rights used in connection with nuclear power generation. (See electric plant instruction 7.)

**321 Structures and improvements (Major only)**.

This account shall include the cost in place of structures and improvements used and



useful in connection with nuclear power generation. (See electric plant instruction 8.)

Note: Include vapor containers and nuclear production roads and railroads in this account.

**322 Reactor plant equipment (Major only)**.

This account shall include the installed cost of reactors, reactor fuel handling and storage equipment, pressurizing equipment, coolant charging equipment, purification and discharging equipment, radioactive waste treatment and disposal equipment, boilers, steam and feed water piping, reactor and boiler apparatus and accessories and other reactor plant equipment used in the production of steam to be used primarily for generating electricity, including auxiliary superheat boilers and associated equipment in systems which change temperatures or pressure of steam from the reactor system.

ITEMS

1. Auxiliary superheat boilers and associated fuel storage handling preparation and burning equipment, etc. (See account 312 Boiler Plant Equipment, for items, but exclude water supply, water flow lines, and steam lines, as well as other equipment not strictly within the superheat function.)
2. Boiler feed system, including feed water heaters, evaporator condensers, heater drain pumps, heater drainers, deaerators, and vent condensers, boiler feed pumps, surge tanks, feed water regulators, feed water measuring equipment, and all associated drivers.
3. Boilers and heat exchangers.
4. Instruments and devices, including all measuring, indicating, and recording equipment for reactor and boiler plant service together with mountings and supports.
5. Lighting systems.
6. Moderators, such as heavy water, graphite, etc., initial charge.

7. Reactor coolant; primary and secondary systems (initial charge).

8. Radioactive waste treatment and disposal equipment, including tanks, ion exchangers, incinerators, condensers, chimneys, and diluting fans and pumps.

9. Foundations and settings, especially constructed for and not expected to outlast the apparatus for which provided.

10. Reactor including shielding, control rods and mechanisms.

11. Reactor fuel handling equipment, including manipulating and extraction tools, underwater viewing equipment, seal cutting and welding equipment, fuel transfer equipment and fuel disassembly machinery.

12. Reactor fuel element failure detection system.

13. Reactor emergency poison container and injection system.

14. Reactor pressurizing and pressure relief equipment, including pressurizing tanks and immersion heaters.

15. Reactor coolant or moderator circulation charging, purification, and discharging equipment, including tanks, pumps, heat exchangers, demineralizers, and storage.

16. Station piping, including pipes, valves, fittings, separators, traps, desuperheaters, hangers, excavation, covering, etc., for station piping system, including all-reactor coolant, steam, condensate, boiler feed and water supply piping, etc., but not condensing water, plumbing, building heating, oil, gas, or air piping.

17. Ventilating equipment.

18. Water purification equipment, including softeners, demineralizers, and accessories, evaporators and accessories, heat exchangers, filters, tanks for filtered or softened water, pumps, motors, etc.

19. Water supply systems, including pumps, motors, strainers, raw-water storage tanks, boiler wash pumps, intake and discharge pipes and tunnels not a part of a building.

20. Reactor plant cranes and hoists, and associated drives.

Note: When the system for supplying boiler or condenser water is elaborate, as when it includes a dam, reservoir, canal, pipe lines, or cooling ponds, the cost of such special facilities shall be charged to a subdivision of account 321, Structures and Improvements.

**323 Turbogenerator units (Major only)**.

This account shall include the cost installed of main turbine-driven units and accessory equipment used in generating electricity by steam.

ITEMS

1. Air cleaning and cooling apparatus, including blowers, drive equipment, air ducts not a part of building, louvers, pumps, hoods, etc.
2. Circulating pumps, including connections between condensers, and intake and discharge tunnels.
3. Condensers, including condensate pumps, air and vacuum pumps ejectors, unloading valves and vacuum breakers, expansion devices, screens, etc.
4. Generator hydrogen gas piping system and hydrogen detrainment equipment, and bulk hydrogen gas storage equipment.
5. Cooling system, including towers, pumps, tanks and piping.



6. Cranes, hoists, etc., including items wholly identified with items listed herein.
7. Excitation system, when identified with main generating units.
8. Fire extinguishing systems.
9. Foundations and settings, especially constructed for and not expected to outlast the apparatus for which provided.
10. Governors.
11. Lighting systems.
12. Lubricating systems, including gauges filters, water separators, tanks, pumps, piping motors, etc.
13. Mechanical meters, including gauges recording instruments, sampling and testing equipment.
14. Piping--main exhaust, including connections between turbogenerator and condenser and between condenser and hotwell.
15. Piping--main steam, including connections from main throttle valve to turbine inlet.
16. Platforms, railings, steps, gratings, etc. appurtenant to apparatus listed herein.
17. Pressure oil systems, including accumulators, pumps, piping, motors, etc.
18. Steelwork, specially constructed for apparatus listed herein.
19. Throttle and inlet valve.
20. Tunnels, intake and discharge, for condenser system, when not a part of structure water screens, etc.
21. Turbogenerators--main, including turbine and generator, field rheostats and electric connections for self-excited units.
22. Water screens, motors, etc.

23 Moisture separators for turbine steam.
24. Turbine lubricating oil (initial charge).

**324 Accessory electric equipment (Major only)**.

This account shall include the cost installed of auxiliary generating apparatus, conversion equipment, and equipment used primarily in connection with the control and switching of electric energy produced by nuclear power, and the protection of electric circuits and equipment, except electric motors used to drive equipment included in other accounts. Such motors shall be included in the account in which the equipment with which they are associated is included.

Note: Do not include in this account transformers and other equipment used for changing the voltage or frequency of electric energy for the purpose of transmission or distribution.

ITEMS

1. Auxiliary generators, including boards, compartments, switching equipment, control equipment, and connections to auxiliary power bus.
2. Excitation system, including motor, turbine and dual-drive exciter sets and rheostats, storage batteries and charging equipment, circuit breakers, panels and accessories, knife switches and accessories, surge arresters, instrument shunts, conductors and conduit, special supports for conduit, generator field and exciter switch panels, exciter bus tie panels, generator and exciter rheostats, etc., special housing, protective screens, etc.
3. Generator main connections, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, current transformers, potential transformers, protective relays, isolated panels and equipment, conductors and conduit, special supports for generator main leads, grounding switch, etc., special housings, protective screens, etc.
4. Station buses, including main, auxiliary, transfer, synchronizing and fault ground buses, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, reactors and accessories, voltage regulators and accessories, compensators, resistors, starting transformers, current transformers, potential transformers, protective relays, storage batteries and charging equipment, isolated panels and equipment, conductors and conduit, special supports, special housings, concrete

pads, general station grounding system, fire-extinguishing system, and test equipment.

5. Station control system, including station switchboards with panel wiring, panels with instruments and control equipment only, panels with switching equipment mounted or mechanically connected, truck-type boards complete, cubicles, station supervisory control boards, generator and exciter signal stands, temperature recording devices, frequency-control equipment, master clocks, watt-hour meters and synchronoscope in the turbine room, station totalizing wattmeter, boiler-room load indicator equipment, storage batteries, panels and charging sets, instrument transformers for supervisory metering, conductors and conduit, special supports for conduit, switchboards, batteries, special housing for batteries, protective screens, doors, etc.

Note: When any item of equipment listed herein is used wholly to furnish power to equipment included in another account, its cost shall be included in such other account

**325 Miscellaneous power plant equipment (Major only)**.

This account shall include the cost installed of miscellaneous equipment in and about the nuclear generating



plant devoted to general station use, and which is not properly includible in any of the foregoing nuclear-power production accounts.

ITEMS

1. Compressed air and vacuum cleaning systems, including tanks, compressors, exhausters, air filters, piping, etc.
2. Cranes and hoisting equipment, including cranes, cars, crane rails, monorails, hoists, etc., with electric and mechanical connections.
3. Fire-extinguishing equipment for general station and site use.
4. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided.
5. Locomotive cranes not includible elsewhere.
6. Locomotives not included elsewhere.
7. Marine equipment, including boats, barges, etc.
8. Miscellaneous belts, pulleys, countershafts, etc.

9. Miscellaneous equipment, including atmospheric and weather recording devices, intrasite communication equipment, laboratory equipment, signal systems, callophones emergency whistles and sirens, fire alarms, insect-control equipment, and other similar equipment.

10. Railway cars or special shipping containers not includible elsewhere.

11. Refrigerating systems, including compressors, pumps, cooling coils, etc.

12. Station maintenance equipment, including lathes, shapers, planers, drill presses, hydraulic presses, grinders, etc., with motors, shafting, hangers, pulleys, etc.

13. Ventilating equipment, including items wholly identified with apparatus listed herein.

14. Station and area radiation monitoring equipment.

Note: When any item of equipment listed herein is wholly used in connection with equipment included in another account, its cost shall be included in such other account.

**330 Land and land rights**.

This account shall include the cost of land and land rights used in connection with hydraulic power generation. (See electric plant instruction 7.) For Major utilities, it shall also include the cost of land and land rights used in connection with (1) the conservation of fish and wildlife, and (2) recreation. Separate subaccounts shall be maintained for each of the above.

**331 Structures and improvements**.

This account shall include the cost in place of structures and improvements used in connection with hydraulic power generation. (See electric plant instruction 8.) For Major utilities, it shall also include the cost in place of structures and improvements used in connection with (1) the conservation of fish and wildlife, and (2) recreation. Separate subaccounts shall be maintained for each of the above.

**332 Reservoirs, dams, and waterways**.

This account shall include the cost in place of facilities used for impounding, collecting, storage, diversion, regulation, and delivery of water used primarily for generating electricity. For Major utilities, it shall also include the cost in place of facilities used in connection with (a) the conservation of fish and wildlife, and (b) recreation. Separate subaccounts shall be maintained for each of the above. (See electric plant instruction 8C.)

ITEMS

1. Bridges and culverts (when not a part of roads or railroads).
2. Clearing and preparing land.
3. Dams, including wasteways, spillways, flash boards, spillway gates with operating and control mechanisms, tunnels, gate houses, and fish ladders.
4. Dikes and embankments.
5. Electric system, including conductors control system, transformers, lighting fixtures, etc.
6. Excavation, including shoring, bracing, bridging, refill, and disposal of excess excavated material.
7. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided.
8. Intakes, including trash racks, rack cleaners, control gates and valves with operating mechanisms, and intake house when not a part of station structure.
9. Platforms, railings, steps, gratings, etc., appurtenant to structures listed herein.
10. Power line wholly identified with items included herein.
11. Retaining walls.
12. Water conductors and accessories, including canals, tunnels, flumes, penstocks pipe conductors, forebays, tailraces, navigation locks and operating mechanisms, waterhammer and surge tanks, and supporting trestles and structures.
13. Water storage reservoirs, including dams, flashboards, spillway gates and operating mechanisms, inlet and outlet tunnels,



regulating valves and valve towers, silt and mud sluicing tunnels with valve or gate towers, and all other structures wholly identified with any of the foregoing items.

**333 Water wheels, turbines and generators**.

This account shall include the cost installed of water wheels and hydraulic turbines (from connection with penstock or flume to tailrace) and generators driven thereby devoted to the production of electricity by water power or for the production of power for industrial or other purposes, if the equipment used for such purposes is a part of the hydraulic power plant works.

ITEMS

1. Exciter water wheels and turbines, including runners, gates, governors, pressure regulators, oil pumps, operating mechanisms, scroll cases, draft tubes, and draft-tube supports.
2. Fire-extinguishing equipment.
3. Foundations and settings, specially constructed for and not expected to outlast the apparatus for which provided.
4. Generator cooling system, including air cooling and washing apparatus, air fans and accessories, air ducts, etc.
5. Generators--main, a.c. or d.c., including field rheostats and connections for self-excited units and excitation system when identified with the generating unit.
6. Lighting systems.
7. Lubricating systems, including gauges, filters, tanks, pumps, piping, etc.
8. Main penstock valves and appurtenances, including main valves, control equipment, bypass valves and fittings, and other accessories.
9. Main turbines and water wheels, including runners, gates, governors, pressure regulators, oil pumps, operating mechanisms, scroll cases, draft tubes, and draft-tube supports.
10. Mechanical meters and recording instruments.
11. Miscellaneous water-wheel equipment, including gauges, thermometers, meters, and other instruments.
12. Platforms, railings, steps, gratings, etc., appurtenant to apparatus listed herein.
13. Scroll case filling and drain system, including gates, pipe, valves, fittings, etc.
14. Water-actuated pressure-regulator system, including tanks and housings, pipes, valves, fittings and insulations, piers and anchorage, and excavation and backfill.

**334 Accessory electric equipment**.

This account shall include the cost installed of auxiliary generating apparatus, conversion equipment, and equipment used primarily in connection with the control and switching of electric energy produced by hydraulic power and the protection of electric circuits and equipment, except electric motors used to drive equipment included in other accounts, such motors being included in the account in which the equipment with which they are associated is included.

ITEMS

1. Auxiliary generators, including boards, compartments, switching equipment, control equipment, and connections to auxiliary power bus.

2. Excitation system, including motor, turbine, and dual-drive exciter sets and rheostats, storage batteries and charging equipment, circuit breakers, panels and accessories, knife switches and accessories, surge arresters, instrument shunts, conductors and conduit, special supports for conduit, generator field and exciter switch panels, exciter bus tie panels, generator and exciter rheostats, etc., special housings, protective screens, etc.

3. Generator main connections, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, current transformers, potential transformers, protective relays, isolated panels and equipment, conductors and conduit, special supports for generator main leads, grounding switch, etc., special housings, protective screens, etc.

4. Station buses, including main, auxiliary, transfer, synchronizing, and fault ground buses, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, reactors and accessories, voltage regulators and accessories, compensators, resistors starting transformers, current transformers, potential transformers, protective relays, storage batteries, and charging equipment, isolated panels and equipment, conductors and conduit, special supports, special fire-extinguishing system, and test equipment.

5. Station control system, including station switchboards with panel wiring panels with instruments and control equipment only, panels with switching equipment mounted or mechanically connected, trucktype boards complete, cubicles, station supervisory control devices, frequency control equipment, master clocks, watt-hour meter, station totalizing watt-meter, storage batteries, panels and charging sets, instrument transformers for supervisory metering,

conductors and conduit, special supports for conduit, switchboards, batteries, special housings for batteries, protective screens, doors, etc.

Note A: Do not include in this account transformers and other equipment used for changing the voltage or frequency of electricity for the purpose of transmission or distribution.

Note B: When any item of equipment listed herein is used wholly to furnish power to equipment, it shall be included in such equipment account.

**335 Miscellaneous power plant equipment**.

This account shall include the cost installed of miscellaneous equipment in and about the hydroelectric generating plant which is devoted to general station use and is not properly includible in other hydraulic production accounts. For Major utilities, it shall also include the cost of equipment used in connection with (a) the conservation of fish and wildlife, and (b) recreation. Separate subaccounts shall be maintained for each of the above.

ITEMS

1. Compressed air and vacuum cleaning systems, including tanks, compressors, exhausters, air filters, piping, etc.
2. Cranes and hoisting equipment, including cranes, cars, crane rails, monorails, hoists, etc., with electric and mechanical connections.
3. Fire-extinguishing equipment for general station use.
4. Foundations and settings, specially constructed for and not expected to outlast the apparatus for which provided.
5. Locomotive cranes not includible elsewhere.
6. Locomotives not includible elsewhere.
7. Marine equipment, including boats, barges, etc.
8. Miscellaneous belts, pulleys, countershafts, etc.
9. Miscellaneous equipment, including atmospheric and weather indicating devices, intrasite communication equipment, laboratory equipment, insect control equipment, signal systems, callophones, emergency whistles and sirens, fire alarms, and other similar equipment.
10. Railway cars, not includible elsewhere.
11. Refrigerating system, including compressors, pumps, cooling

coils, etc.

12. Station maintenance equipment, including lathes, shapers, planers, drill presses, hydraulic presses, grinders, etc., with motors, shafting, hangers, pulleys, etc.

13. Ventilating equipment, including items wholly identified with apparatus listed herein.

Note: When any item of equipment, listed herein is used wholly in connection with equipment included in another account, its cost shall be included in such other account.

**336 Roads, railroads and bridges**.

This account shall include the cost of roads, railroads, trails, bridges, and trestles used primarily as production facilities. It includes also those roads, etc., necessary to connect the plant with highway transportation systems, except when such roads are dedicated to public use and maintained by public authorities.

ITEMS

1. Bridges, including foundations, piers, girders, trusses, flooring, etc.
2. Clearing land.
3. Railroads, including grading, ballast, ties, rails, culverts, hoists, etc.
4. Roads, including grading, surfacing, culverts, etc.
5. Structures, constructed and maintained in connection with items listed herein.
6. Trails, including grading, surfacing, culverts, etc.
7. Trestles, including foundations, piers, girders, trusses, flooring, etc.

Note A: Roads intended primarily for connecting employees' houses with the powerplant, and roads used primarily in connection with fish and wildlife, and recreation activities, shall not be included herein but in account 331, Structures and Improvements.

Note B: The cost of temporary roads, bridges, etc. necessary during the period of construction but abandoned or dedicated to public use upon completion of the plant, shall not be included herein but shall be charged to the accounts appropriate for the construction.

**340 Land and land rights**.

This account shall include the cost of land and land rights used in connection with other power generation. (See electric plant instruction 7.)

**341 Structures and improvements**.

This account shall include the cost in place of structures and improvements used in connection with other power generation. (See electric plant instruction 8.)



**342 Fuel holders, producers, and accessories**.

This account shall include the cost installed of fuel handling and storage equipment used between the point of fuel delivery to the station and the intake pipe through which fuel is directly drawn to the engine, also the cost of gas producers and accessories devoted to the production of gas for use in prime movers driving main electric generators.

ITEMS

1. Blower and fans.
2. Boilers and pumps.
3. Economizers.
4. Exhauster outfits.
5. Flues and piping.
6. Pipe system.
7. Producers.
8. Regenerators.
9. Scrubbers.
10. Steam injectors.
11. Tanks for storage of oil, gasoline, etc.
12. Vaporizers.

**343 Prime movers**.

This account shall include the cost installed of Diesel or other prime movers devoted to the generation of electric energy, together with their auxiliaries.

ITEMS

1. Air-filtering system.
2. Belting, shafting, pulleys, reduction gearing, etc.
3. Cooling system, including towers, pumps, tanks, and piping.
4. Cranes, hoists, etc., including items wholly identified with apparatus listed herein.
5. Engines, Diesel, gasoline, gas, or other internal combustion.
6. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided.
7. Governors.
8. Ignition system.
9. Inlet valve.
10. Lighting systems.
11. Lubricating systems, including filters, tanks, pumps, and piping.
12. Mechanical meters, including gauges, recording instruments, sampling, and testing equipment.
13. Mufflers.
14. Piping.
15. Starting systems, compressed air, or other, including compressors and drives, tanks, piping, motors, boards and connections, storage tanks, etc.
16. Steelwork, specially constructed for apparatus listed herein.
17. Waste heat boilers, antifluctuators, etc.

**344 Generators**.

This account shall include the cost installed of Diesel or other power driven main generators.

ITEMS

1. Cranes, hoists, etc., including items wholly identified with such apparatus.
2. Fire-extinguishing equipment.
3. Foundations and settings, specially constructed for and not expected to outlast the apparatus for which provided.
4. Generator cooling system, including air cooling and washing apparatus, air fans and accessories, air ducts, etc.
5. Generators--main, a.c. or d.c., including field rheostats and connections for self-excited units and excitation system when identified

with the generating unit.
6. Lighting systems.
7. Lubricating system, including tanks, filters, strainers, pumps, piping, coolers, etc.
8. Mechanical meters, and recording instruments.
9. Platforms, railings, steps, gratings, etc., appurtenant to apparatus listed herein.

Note: If prime movers and generators are so integrated that it is not practical to classify them separately, the entire unit may be included in account 344, Generators.

**345 Accessory electric equipment**.

This account shall include the cost installed of auxiliary generating apparatus, conversion equipment, and equipment used primarily in connection with the control and switching of electric energy produced in other power generating stations, and the protection of electric circuits and equipment, except electric motors used to drive equipment included in other accounts. Such motors shall be included in the account in which the equipment with which it is associated is included.

ITEMS

1. Auxiliary generators, including boards, compartments, switching equipment, control equipment, and connections to auxiliary power bus.
2. Excitation system, including motor, turbine and dual-drive exciter sets and rheostats, storage batteries and charging equipment, circuit breakers, panels and accessories, knife switches and accessories, surge arresters, instrument shunts, conductors and conduit, special supports for conduit, generator field and exciter switch panels, exciter



bus tie panels, generator and exciter rheostats, etc., special housings, protective screens, etc.
3. Generator main connections, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, current transformers, potential transformers, protective relays, isolated panels and equipment, conductors and conduit, special supports for generator main leads, grounding switch,

etc., special housing, protective screens, etc.

4. Station control system, including station switchboards with panel wiring, panels with instruments and control equipment only, panels with switching equipment mounted or mechanically connected, trunktype boards complete, cubicles, station supervisory control boards, generator and exciter signal stands, temperature-recording devices, frequency control equipment, master clocks, watt-hour meter, station totalizing wattmeter, storage batteries, panels and charging sets, instrument transformers for supervisory metering, conductors and conduit, special supports for conduit, switchboards, batteries, special housing for batteries, protective screens, doors, etc.

5. Station buses, including main, auxiliary transfer, synchronizing and fault ground buses, including oil curcuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, reactors and accessories, voltage regulators and accessories, compensators, resistors, starting transformers, current transformers, potential transformers, protective relays, storage batteries and charging equipment, isolated panels and equipment, conductors and conduit, special supports, special housings, concrete pads, general station ground system, special fire-extinguishing system, and test equipment.

Note A: Do not include in this account transformers and other equipment used for changing the voltage or frequency of electric energy for the purpose of transmission or distribution.

Note B: When any item of equipment listed herein is used wholly to furnish power to equipment included in another account, its cost shall be included in such other account.

**346 Miscellaneous power plant equipment**.

This account shall include the cost installed of miscellaneous equipment in and about the other power generating plant, devoted to general station use, and not properly includible in any of the foregoing other power production accounts.

ITEMS

1. Compressed air and vacuum cleaning systems, including tanks, compressors, exhausters, air filters, piping, etc.

2. Cranes and hoisting equipment, including cranes, cars, crane

rails, monorails, hoists, etc., with electric and mechanical connections.

3. Fire-extinguishing equipment for general station use.

4. Foundations and settings, specially constructed for and not expected to outlast the apparatus for which provided.

5. Miscellaneous equipment, including atmospheric and weather indicating devices, intrasite communication equipment, laboratory equipment, signal systems, callophones, emergency whistles and sirens, fire alarms, and other similar equipment.

6. Miscellaneous belts, pulleys, countershafts, etc.

7. Refrigerating system including compressors, pumps, cooling coils, etc.

8. Station maintenance equipment, including lathes, shapers, planers, drill presses, hydraulic presses, grinders, etc., with motors, shafting, hangers, pulleys, etc.

9. Ventilating equipment, including items wholly identified with apparatus listed herein.

Note: When any item of equipment, listed herein is used wholly in connection with equipment included in another account, its cost shall be included in such other account.

**350 Land and land rights**.

This account shall include the cost of land and land rights used in connection with transmission operations. (See electric plant instruction 7.)

**351 [Reserved]**

**352 Structures and improvements**.

This account shall include the cost in place of structures and improvements used in connection with transmission operations. (See electric plant instruction 8.)

**353 Station equipment**.

This account shall include the cost installed of transforming, conversion, and switching equipment used for the purpose of changing the characteristics of electricity in connection with its transmission or for controlling transmission circuits.

ITEMS

1. Bus compartments, concrete, brick, and sectional steel, including items permanently attached thereto.
2. Conduit, including concrete and iron duct runs not a part of a building.
3. Control equipment, including batteries battery charging equipment, transformers, remote relay boards, and connections.
4. Conversion equipment, including transformers, indoor and outdoor, frequency changers, motor generator sets, rectifiers, synchronous converters, motors, cooling equipment, and associated connections.
5. Fences.
6. Fixed and synchronous condensers, including transformers, switching equipment blowers, motors and connections.
7. Foundations and settings, specially constructed for and not expected to outlast the apparatus for which provided.
8. General station equipment, including air compressors, motors, hoists, cranes, test equipment, ventilating equipment, etc.
9. Platforms, railings, steps, gratings, etc. appurtenant to apparatus listed herein.
10. Primary and secondary voltage connections, including bus runs and supports, insulators, potheads, lightning arresters, cable and wire runs from and to outdoor connections or to manholes and the associated regulators, reactors, resistors, surge arresters, and accessory equipment.
11. Switchboards, including meters, relays, control wiring, etc.
12. Switching equipment, indoor and outdoor, including oil circuit breakers and operating mechanisms, truck switches, and disconnect switches.
13. Tools and appliances.

**354 Towers and fixtures**.

This account shall include the cost installed of towers and appurtenant fixtures used for supporting overhead transmission conductors.

ITEMS

1. Anchors, guys, braces.

2. Brackets.
3. Crossarms, including braces.
4. Excavation, backfill, and disposal of excess excavated material.
5. Foundations.
6. Guards.
7. Insulator pins and suspension bolts.
8. Ladders and steps.
9. Railings, etc.
10. Towers.

**355 Poles and fixtures**.

This account shall include the cost installed of transmission line poles, wood, steel, concrete, or other material, together with appurtenant fixtures used for supporting overhead transmission conductors.

ITEMS

1. Anchors, head arm and other guys, including guy guards, guy clamps, strain insulators, pole plates, etc.
2. Brackets.
3. Crossarms and braces.
4. Excavation and backfill, including disposal of excess excavated material.
5. Extension arms.
6. Gaining, roofing stenciling, and tagging.
7. Insulator pins and suspension bolts.
8. Paving.
9. Pole steps.
10. Poles, wood, steel, concrete, or other material.
11. Racks complete with insulators.
12. Reinforcing and stubbing.
13. Settings.
14. Shaving and painting.

**356 Overhead conductors and devices**.

This account shall include the cost installed of overhead conductors and devices used for transmission purposes.

ITEMS

1. Circuit breakers.
2. Conductors, including insulated and bare wires and cables.
3. Ground wires and ground clamps.
4. Insulators, including pin, suspension, and other types.
5. Lightning arresters.
6. Switches.
7. Other line devices.

**357 Underground conduit**.

This account shall include the cost installed of underground conduit and tunnels used for housing transmission cables or wires. (See electric plant instruction 14.)

ITEMS

1. Conduit, concrete, brick or tile, including iron pipe, fiber pipe, Murray duct, and standpipe on pole or tower.
2. Excavation, including shoring, bracing, bridging, backfill, and disposal of excess excavated material.
3. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided.
4. Lighting systems.
5. Manholes, concrete or brick, including iron or steel, frames and covers, hatchways, gratings, ladders, cable racks and hangers, etc., permanently attached to manholes.
6. Municipal inspection.



7. Pavement disturbed, including cutting and replacing pavement, pavement base and sidewalks.
8. Permits.
9. Protection of street openings.
10. Removal and relocation of subsurface obstructions.
11. Sewer connections, including drains, traps, tide valves, check valves, etc.
12. Sumps, including pumps.
13. Ventilating equipment.

**358 Underground conductors and devices**.

This account shall include the cost installed of underground conductors and devices used for transmission purposes.

ITEMS

1. Armored conductors, buried, including insulators, insulating materials, splices, potheads, trenching, etc.
2. Armored conductors, submarine, including insulators, insulating materials, splices in terminal chambers, potheads, etc.
3. Cables in standpipe, including pothead and connection from terminal chamber of manhole to insulators on pole.
4. Circuit breakers.
5. Fireproofing, in connection with any items listed herein.
6. Hollow-core oil-filled cable, including straight or stop joints pressure tanks, auxiliary air tanks, feeding tanks, terminals, potheads and connections, ventilating equipment, etc.
7. Lead and fabric covered conductors, including insulators, compound filled, oil filled, or vacuum splices, potheads, etc.
8. Lightning arresters.
9. Municipal inspection.
10. Permits.
11. Protection of street openings.
12. Racking of cables.
13. Switches.
14. Other line devices.

**359 Roads and trails**.

This account shall include the cost of roads, trails, and bridges used primarily as transmission facilities.

ITEMS

1. Bridges, including foundation piers, girders, trusses, flooring, etc.
2. Clearing land.
3. Roads, including grading, surfacing, culverts, etc.
4. Structures, constructed and maintained in connection with items included herein.
5. Trails, including grading, surfacing, culverts, etc.

Note: The cost of temporary roads, bridges, etc., necessary during the period of construction but abandoned or dedicated to public use upon completion of the plant, shall be charged to the accounts appropriate for the construction.

**360 Land and land rights**.

This account shall include the cost of land and land rights used in connection with distribution operations. (See electric plant instruction 7.)

Note: Do not include in this account the cost of permits to erect poles, towers, etc., or to trim trees. (See account 364, Poles, Towers and Fixtures, and account 365, Overhead Conductors and Devices.)

**361 Structures and improvements**.

This account shall include the cost in place of structures and improvements used in connection with distribution operations. (See electric plant instruction 8.)

**362 Station equipment**.

This account shall include the cost installed of station equipment, including transformer banks, etc., which are used for the purpose of changing the characteristics of electricity in connection with its distribution.

ITEMS

1. Bus compartments, concrete, brick and sectional steel, including items permanently attached thereto.
2. Conduit, including concrete and iron duct runs not part of building.
3. Control equipment, including batteries, battery charging equipment, transformers, remote relay boards, and connections.
4. Conversion equipment, indoor and outdoor, frequency changers, motor generator sets, rectifiers, synchronous converters, motors, cooling equipment, and associated connections.
5. Fences.
6. Fixed and synchronous condensers, including transformers, switching equipment, blowers, motors, and connections.
7. Foundations and settings, specially constructed for and not

expected to outlast the apparatus for which provided.

8. General station equipment, including air compressors, motors, hoists, cranes, test equipment, ventilating equipment, etc.

9. Platforms, railings, steps, gratings, etc., appurtenant to apparatus listed herein.

10. Primary and secondary voltage connections, including bus runs and supports, insulators, potheads, lightning arresters,



cable and wire runs from and to outdoor connections or to manholes and the associated regulators, reactors, resistors, surge arresters, and accessory equipment.

11. Switchboards, including meters, relays, control wiring, etc.

12. Switching equipment, indoor and outdoor, including oil circuit breakers and operating mechanisms, truck switches, disconnect switches.

Note: The cost of rectifiers, series transformers, and other special station equipment devoted exclusively to street lighting service shall not be included in this account, but in account 373, Street Lighting and Signal Systems.

**363 Storage battery equipment**.

This account shall include the cost installed of storage battery equipment used for the purpose of supplying electricity to meet emergency or peak demands.

ITEMS

1. Batteries, including elements, tanks, tank insulators, etc.

2. Battery room connections, including cable or bus runs and connections.

3. Battery room flooring, when specially laid for supporting batteries.

4. Charging equipment, including motor generator sets and other charging equipment and connections, and cable runs from generator or station bus to battery room connections.

5. Miscellaneous equipment, including instruments, water stills, etc.

6. Switching equipment, including endcell switches and connections, boards and panels, used exclusively for battery control, not part of

general station switchboard.
7. Ventilating equipment, including fans and motors, louvers, and ducts not part of building.

Note: Storage batteries used for control and general station purposes shall not be included in this account but in the account appropriate for their use.

**364 Poles, towers and fixtures**.

This account shall include the cost installed of poles, towers, and appurtenant fixtures used for supporting overhead distribution conductors and service wires.

ITEMS

1. Anchors, head arm, and other guys, including guy guards, guy clamps, strain insulators, pole plates, etc.
2. Brackets.
3. Crossarms and braces.
4. Excavation and backfill, including disposal of excess excavated material.
5. Extension arms.
6. Foundations.
7. Guards.
8. Insulator pins and suspension bolts.
9. Paving.
10. Permits for construction.
11. Pole steps and ladders.
12. Poles, wood, steel, concrete, or other material.
13. Racks complete with insulators.
14. Railings.
15. Reinforcing and stubbing.
16. Settings.
17. Shaving, painting, gaining, roofing, stenciling, and tagging.
18. Towers.
19. Transformer racks and platforms.

**365 Overhead conductors and devices**.

This account shall include the cost installed of overhead conductors and devices used for distribution purposes.

ITEMS

1. Circuit breakers.
2. Conductors, including insulated and bare wires and cables.
3. Ground wires, clamps, etc.
4. Insulators, including pin, suspension, and other types, and tie wire or clamps.
5. Lightning arresters.
6. Railroad and highway crossing guards.
7. Splices.
8. Switches.
9. Tree trimming, initial cost including the cost of permits therefor.
10. Other line devices.

Note: The cost of conductors used solely for street lighting or signal systems shall not be included in this account but in account 373, Street Lighting and Signal Systems.

**366 Underground conduit**.

This account shall include the cost installed of underground conduit and tunnels used for housing distribution cables or wires.

ITEMS

1. Conduit, concrete, brick and tile, including iron pipe, fiber pipe, Murray duct, and standpipe on pole or tower.
2. Excavation, including shoring, bracing, bridging, backfill, and disposal of excess excavated material.
3. Foundations and settings specially constructed for and not expected to outlast the apparatus for which constructed.
4. Lighting systems.



5. Manholes, concrete or brick, including iron or steel frames and covers, hatchways, gratings, ladders, cable racks and hangers, etc., permanently attached to manholes.
6. Municipal inspection.
7. Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks.

8. Permits.
9. Protection of street openings.
10. Removal and relocation of subsurface obstructions.
11. Sewer connections, including drains, traps, tide valves, check valves, etc.
12. Sumps, including pumps.
13. Ventilating equipment.

Note: The cost of underground conduit used solely for street lighting or signal systems shall be included in account 373, Street Lighting and Signal Systems.

**367 Underground conductors and devices**.

This account shall include the cost installed of underground conductors and devices used for distribution purposes.

ITEMS

1. Armored conductors, buried, including insulators, insulating materials, splices, potheads, trenching, etc.
2. Armored conductors, submarine, including insulators, insulating materials, splices in terminal chamber, potheads, etc.
3. Cables in standpipe, including pothead and connection from terminal chamber or manhole to insulators on pole.
4. Circuit breakers.
5. Fireproofing, in connection with any items listed herein.
6. Hollow-core oil-filled cable, including straight or stop joints, pressure tanks, auxiliary air tanks, feeding tanks, terminals, potheads and connections, etc.
7. Lead and fabric covered conductors, including insulators, compound-filled, oil-filled or vacuum splices, potheads, etc.
8. Lightning arresters.
9. Municipal inspection.
10. Permits.
11. Protection of street openings.
12. Racking of cables.
13. Switches.
14. Other line devices.

Note: The cost of underground conductors and devices used solely for street lighting or signal systems shall be included in account 373, Street Lighting and Signal Systems.

**368 Line transformers**.

A. This account shall include the cost installed of overhead and underground distribution line transformers and poletype and underground voltage regulators owned by the utility, for use in transforming electricity to the voltage at which it is to be used by the customer, whether actually in service or held in reserve.

B. When a transformer is permanently retired from service, the original installed cost thereof shall be credited to this account.

C. The records covering line transformers shall be so kept that the utility can furnish the number of transformers of various capacities in service and those in reserve, and the location and the use of each transformer.

ITEMS

1. Installation, labor of (first installation only).
2. Transformer cut-out boxes.
3. Transformer lightning arresters.
4. Transformers, line and network.
5. Capacitors.
6. Network protectors.

Note: The cost of removing and resetting line transformers shall not be charged to this account but to account 583, Overhead Line Expenses, or account 584, Underground Line Expenses (for Nonmajor utilities, account 561, Line and Station Labor, or account 562, Line and Station Supplies and Expenses), as appropriate. The cost of line transformers used solely for street lighting or signal systems shall be included in account 373, Street Lighting and Signal Systems.

**369 Services**.

This account shall include the cost installed of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the distribution box or manhole, or the top of the pole of the distribution line, to the point of connection with the customer's outlet or wiring. Conduit used for underground service conductors shall be included herein.

ITEMS

1. Brackets.
2. Cables and wires.
3. Conduit.
4. Insulators.
5. Municipal inspection.
6. Overhead to underground, including conduit or standpipe and conductor from last



splice on pole to connection with customer's wiring.
7. Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks.
8. Permits.
9. Protection of street openings.
10. Service switch.
11. Suspension wire.

**370 Meters**.

A. This account shall include the cost installed of meters or devices and appurtenances thereto, for use in measuring the electricity delivered to its users, whether actually in service or held in reserve.

B. When a meter is permanently retired from service, the installed cost included herein shall be credited to this account.

C. The records covering meters shall be so kept that the utility can furnish information as to the number of meters of various capacities in service and in reserve as well as the location of each meter owned.

ITEMS

1. Alternating current, watt-hour meters.
2. Current limiting devices.
3. Demand indicators.
4. Demand meters.
5. Direct current watt-hour meters.
6. Graphic demand meters.
7. Installation, labor of (first installation only).
8. Instrument transformers.
9. Maximum demand meters.

10. Meter badges and their attachments.
11. Meter boards and boxes.
12. Meter fittings, connections, and shelves (first set).
13. Meter switches and cut-outs.
14. Prepayment meters.
15. Protective devices.
16. Testing new meters.

Note A: This account shall not include meters for recording output of a generating station, substation meters, etc. It includes only those meters used to record energy delivered to customers.

Note B: The cost of removing and resetting meters shall be charged to account 586, Meter Expenses (for Nonmajor utilities, account 556, Meter Expenses).

**371 Installations on customers' premises**.

This account shall include the cost installed of equipment on the customer's side of a meter when the utility incurs such cost and when the utility retains title to and assumes full responsibility for maintenance and replacement of such property. This account shall not include leased equipment, for which see account 372, Leased Property on Customers' Premises.

Items

1. Cable vaults.
2. Commercial lamp equipment.
3. Foundations and settings specially provided for equipment included herein.
4. Frequency changer sets.
5. Motor generator sets.
6. Motors.
7. Switchboard panels, high or low tension.
8. Wire and cable connections to incoming cables.

Note: Do not include in this account any costs incurred in connection with merchandising, jobbing, or contract work activities.

**372 Leased property on customers' premises**.

This account shall include the cost of electric motors, transformers, and other equipment on customers' premises (including municipal corporations), leased or loaned to customers, but not including property held for sale.

Note A: The cost of setting and connecting such appliances or equipment on the premises of customers and the cost of resetting or removal shall not be charged to this account but to operating expenses, account 587, Customer Installations Expenses (for Nonmajor utilities, account 567, Customer Installations Expenses).

Note B: Do not include in this account any costs incurred in connection with merchandising, jobbing, or contract work activities.

**373 Street lighting and signal systems**.

This account shall include the cost installed of equipment used wholly for public street and highway lighting or traffic, fire alarm, police, and other signal systems.

ITEMS

1. Armored conductors, buried or submarine, including insulators, insulating materials, splices, trenching, etc.
2. Automatic control equipment.
3. Conductors, overhead or underground, including lead or fabric covered, parkway cables, etc., including splices, insulators, etc.



4. Lamps, are, incandescent, or other types, including glassware, suspension fixtures, brackets, etc.
5. Municipal inspection.
6. Ornamental lamp posts.
7. Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks.
8. Permits.
9. Posts and standards.
10. Protection of street openings.
11. Relays or time clocks.
12. Series contactors.
13. Switches.

14. Transformers, pole or underground.

**389 Land and land rights**.

This account shall include the cost of land and land rights used for utility purposes, the cost of which is not properly includible in other land and land rights accounts. (See electric plant instruction 7.)

**390 Structures and improvements**.

This account shall include the cost in place of structures and improvements used for utility purposes, the cost of which is not properly includible in other structures and improvements accounts (See electric plant instruction 8.)

**391 Office furniture and equipment**.

This account shall include the cost of office furniture and equipment owned by the utility and devoted to utility service, and not permanently attached to buildings, except the cost of such furniture and equipment which the utility elects to assign to other plant accounts on a functional basis.

ITEMS

1. Bookcases and shelves.
2. Desks, chairs, and desk equipment.
3. Drafting-room equipment.
4. Filing, storage, and other cabinets.
5. Floor covering.
6. Library and library equipment.
7. Mechanical office equipment, such as accounting machines, typewriters, etc.
8. Safes.
9. Tables.

**392 Transportation equipment**.

This account shall include the cost of transportation vehicles used for utility purposes.

ITEMS

1. Airplanes.
2. Automobiles.
3. Bicycles.
4. Electrical vehicles.
5. Motor trucks.
6. Motorcycles.
7. Repair cars or trucks.
8. Tractors and trailers.
9. Other transportation vehicles.

**393 Stores equipment**.

This account shall include the cost of equipment used for the receiving, shipping, handling, and storage of materials and supplies.

ITEMS

1. Chain falls.
2. Counters.
3. Cranes (portable).
4. Elevating and stacking equipment (portable).
5. Hoists.
6. Lockers.
7. Scales.
8. Shelving.
9. Storage bins.
10. Trucks, hand and power driven.
11. Wheelbarrows.

**394 Tools, shop and garage equipment**.

This account shall include the cost of tools, implements, and equipment used in construction, repair work, general shops and garages and not specifically provided for or includible in other accounts.

ITEMS

1. Air compressors.
2. Anvils.
3. Automobile repair shop equipment.
4. Battery charging equipment.
5. Belts, shafts and countershafts.

6. Boilers.
7. Cable pulling equipment.
8. Concrete mixers.
9. Drill presses.
10. Derricks.
11. Electric equipment.
12. Engines.
13. Forges.
14. Furnaces.
15. Foundations and settings specially constructed for and not expected to outlast the equipment for which provided.
16. Gas producers.
17. Gasoline pumps, oil pumps and storage tanks.
18. Greasing tools and equipment.
19. Hoists.
20. Ladders.
21. Lathes.
22. Machine tools.
23. Motor-driven tools.



24. Motors.
25. Pipe threading and cutting tools
26. Pneumatic tools.
27. Pumps.
28. Riveters.
29. Smithing equipment.
30. Tool racks.
31. Vises.
32. Welding apparatus.
33. Work benches.

**395 Laboratory equipment**.

This account shall include the cost installed of laboratory equipment used for general laboratory purposes and not specifically provided for or includible in other departmental or functional plant accounts.

ITEMS

1. Ammeters.
2. Current batteries.
3. Frequency changers.
4. Galvanometers.
5. Inductometers.
6. Laboratory standard millivolt meters.
7. Laboratory standard volt meters.
8. Meter-testing equipment.
9. Millivolt meters.
10. Motor generator sets.
11. Panels.
12. Phantom loads.
13. Portable graphic ammeters, voltmeters, and wattmeters.
14. Portable loading devices.
15. Potential batteries.
16. Potentiometers.
17. Rotating standards.
18. Standard cell, reactance, resistor, and shunt.
19. Switchboards.
20. Synchronous timers.
21. Testing panels.
22. Testing resistors.
23. Transformers.
24. Voltmeters.
25. Other testing, laboratory, or research equipment not provided for elsewhere.

**396 Power operated equipment**.

This account shall include the cost of power operated equipment used in construction or repair work exclusive of equipment includible in other accounts. Include, also, the tools and accessories acquired for use with such equipment and the vehicle on which such equipment is mounted.

ITEMS

1. Air compressors, including driving unit and vehicle.
2. Back filling machines.
3. Boring machines.
4. Bulldozers.
5. Cranes and hoists.

6. Diggers.
7. Engines.
8. Pile drivers.
9. Pipe cleaning machines.
10. Pipe coating or wrapping machines.
11. Tractors--Crawler type.
12. Trenchers.
13. Other power operated equipment.

Note: It is intended that this account include only such large units as are generally self-propelled or mounted on movable equipment.

**397 Communication equipment**.

This account shall include the cost installed of telephone, telegraph, and wireless equipment for general use in connection with utility operations.

ITEMS

1. Antennae.
2. Booths.
3. Cables.
4. Distributing boards.
5. Extension cords.
6. Gongs
7. Hand sets, manual and dial.
8. Insulators.
9. Intercommunicating sets.
10. Loading coils.
11. Operators' desks.
12. Poles and fixtures used wholly for telephone or telegraph wire.
13. Radio transmitting and receiving sets.
14. Remote control equipment and lines.
15. Sending keys.
16. Storage batteries
17. Switchboards.
18. Telautograph circuit connections.
19. Telegraph receiving sets.
20. Telephone and telegraph circuits.
21. Testing instruments.
22. Towers.

23. Underground conduit used wholly for telephone or telegraph wires and cable wires.

**398 Miscellaneous equipment**.

This account shall include the cost of equipment, apparatus, etc., used in the utility operations, which is not includible in any other account of this system of accounts.

ITEMS

1. Hospital and infirmary equipment.
2. Kitchen equipment.
3. Employees' recreation equipment.
4. Radios.
5. Restaurant equipment.
6. Soda fountains.
7. Operators' cottage furnishings.

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8. Other miscellaneous equipment.

Note: Miscellaneous equipment of the nature indicated above wherever practicable shall be included in the utility plant accounts on a functional basis.

**399 Other tangible property**.

This account shall include the cost of tangible utility plant not provided for elsewhere.

Income Chart of Accounts

1. Utility Operating Income

400 Operating revenues.
401 Operation expense.
402 Maintenance expense.
403 Depreciation expense.
404 Amortization of limited-term electric plant.
405 Amortization of other electric plant.

406  Amortization of electric plant acquisition adjustments.
407  Amortization of property losses, unrecovered plant and regulatory study costs.
407.3  Regulatory debits.
407.4  Regulatory credits.
408  [Reserved]
408.1  Taxes other than income taxes, utility operating income.
409  [Reserved]
409.1  Income taxes, utility operating income.
410  [Reserved]
410.1  Provisions for deferred income taxes, utility operating income.
411  [Reserved]
411.1  Provision for deferred income taxes--Credit, utility operating income.
411.3  [Reserved]
411.4  Investment tax credit adjustments, utility operations.
411.6  Gains from disposition of utility plant.
411.7  Losses from disposition of utility plant.
411.8  Gains from disposition of allowances.
411.9  Losses from disposition of allowances.
412  Revenues from electric plant leased to others.
413  Expenses of electric plant leased to others.
414  Other utility operating income.

2. Other Income and Deductions

a. other income

415  Revenues from merchandising, jobbing, and contract work.
416  Costs and expenses of merchandising, jobbing, and contract work.
417  Revenues from nonutility operations.
417.1  Expenses of nonutility operations.
418  Nonoperating rental income.
418.1  Equity in earnings of subsidiary companies (Major only).
419  Interest and dividend income.
419.1  Allowance for other funds used during construction.
420  Investment tax credits.
421  Miscellaneous nonoperating income.
421.1  Gain on disposition of property.

b. other income deductions

421.2 Loss on disposition of property.
425 Miscellaneous amortization.
426 [Reserved]
426.1 Donations.
426.2 Life insurance.
426.3 Penalties.
426.4 Expenditures for certain civic, political and related activities.
426.5 Other deductions.

Total other income deductions.

Total Other Income and Deductions.

c. taxes applicable to other income and deductions

408.2 Taxes other than income taxes, other income and deductions.
409.2 Income tax, other income and deductions.
409.3 Income taxes, extraordinary items.
410.2 Provision for deferred income taxes, other income and deductions.
411.2 Provision for deferred income taxes--Credit, other income and deductions.
411.5 Investment tax credit adjustments, nonutility operations.
420 Investment tax credits.

Total taxes on other income and deductions.

Net other income and deductions.

3. Interest Charges

427 Interest on long-term debt.
428 Amortization of debt discount and expense.
428.1 Amortization of loss on reacquired debt.
429 Amortization of premium on debt-Cr.
429.1 Amortization of gain on reacquired debt--Credit.
430 Interest on debt to associated companies.
431 Other interest expense.
432 Allowance for borrowed funds used during construction--Credit.

4. Extraordinary Items

434 Extraordinary income.

435 Extraordinary deductions.

# APPENDIX J

## Load and Reliability Driven Line Extensions Description and Justification

**Title:** **Blue Shank Road Three Phase Conversion**

**Location:** **Wilmot Valley**

**Line Type:** **Distribution – Three Phase Conversion**

**Distance:** **8.25 km**

**Amount:** **$1,483,000**

**Project Description**

This project involves converting lines KN80086, KN80085, KN80092, and AB00340 from single phase to three phase along Blue Shank Road (Route 107), starting near civic address #1641 and ending near civic address #15 (intersection of Route 1A), as shown in Figure 1. This project also includes filling in a 100-metre gap between lines KN80092 and AB00340. Load from a portion of AB00312 (from Delany Road to Blue Shank Road) and all its single phase branch lines (all currently sourced from the Bedeque feeder out of the Albany substation) will then be transferred to the new three phase line from Blue Shank Road, as shown in Figure 2, resulting in a load transfer of approximately 330 customers.

**Justification**

The primary objective of this project is to reduce the load on the Bedeque feeder as it is a long, rural circuit that is experiencing customer-driven load growth. The load being transferred is at the end of the Bedeque feeder and is at risk of reduced voltage support, as load increases along the circuit. This load will be transferred to the Norboro feeder from the Kensington substation through the new Blue Shank Road three phase extension.

The Bedeque feeder circuit currently has 1,750 customers over 153 km, and a peak load of 7.4 MVA. The Norboro feeder currently has 846 customers over 83 km, and a peak load of 3.9 MVA. Following the three phase conversion and load transfer, the Bedeque feeder will have 1,420 customers over 131 km with an estimated load of 5.8 MVA, and the Norboro feeder will have 1,176 customers over 105 km with an estimated load of 5.4 MVA.

This project is justified based on the obligation to provide customers with equitable access to a safe, reliable, and adequate supply of power and cannot be deferred.

## Costing Methodology

A breakdown of the budget for the Blue Shank Road three phase conversion project is shown in Table 1.

| TABLE 1<br>Breakdown of Proposed Budget<br>Blue Shank Road Three Phase Conversion | |
|---|---|
| **Description** | **Budget** |
| Material | $ 233,000 |
| Contractor Labour | 1,036,000 |
| Internal Labour and Transportation | 214,000 |
| **TOTAL** | **$ 1,483,000** |

## Construction

The existing lines along Blue Shank Road have a mixture 2/0 Quail conductor (rated for 270 amps) and #4 Swan conductor (rated for 140 amps). This conductor will be replaced with 477 Cosmos conductor, which is rated for 584 amps. Construction will be on the same side of the road as the existing line to utilize main line and service poles that are in good condition and do not require replacement.

A permit from the Department of Transportation and Infrastructure will be required, and traffic control will be necessary for this project as the roads are narrow and traffic volume can be high at times.

Construction is scheduled to begin in the second quarter of 2025, with 6 crews working for 8 weeks to complete the project.

## Future Commitments

This is not a multi-year project.

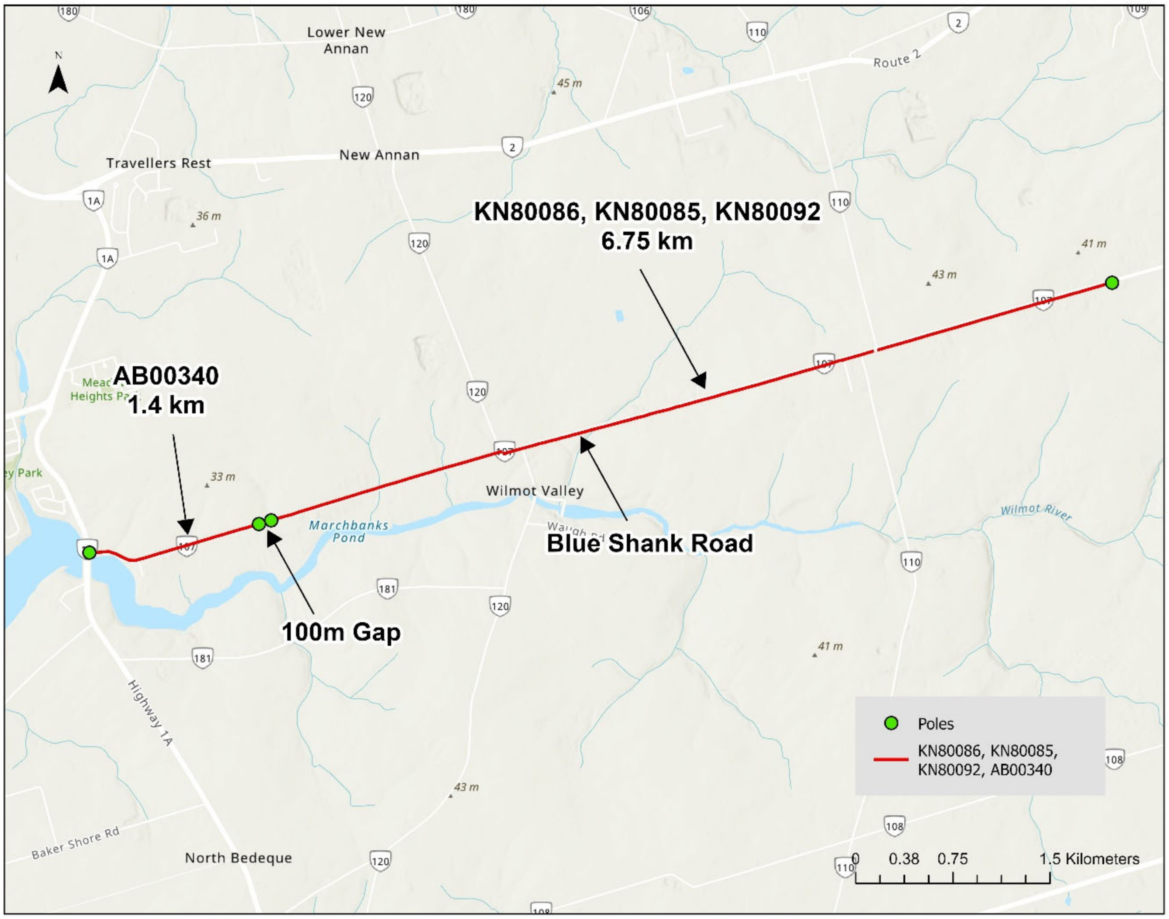


*Figure 1*
*Scope of 8.25 km Blue Shank Road three phase line conversion, Wilmot Valley, PE*

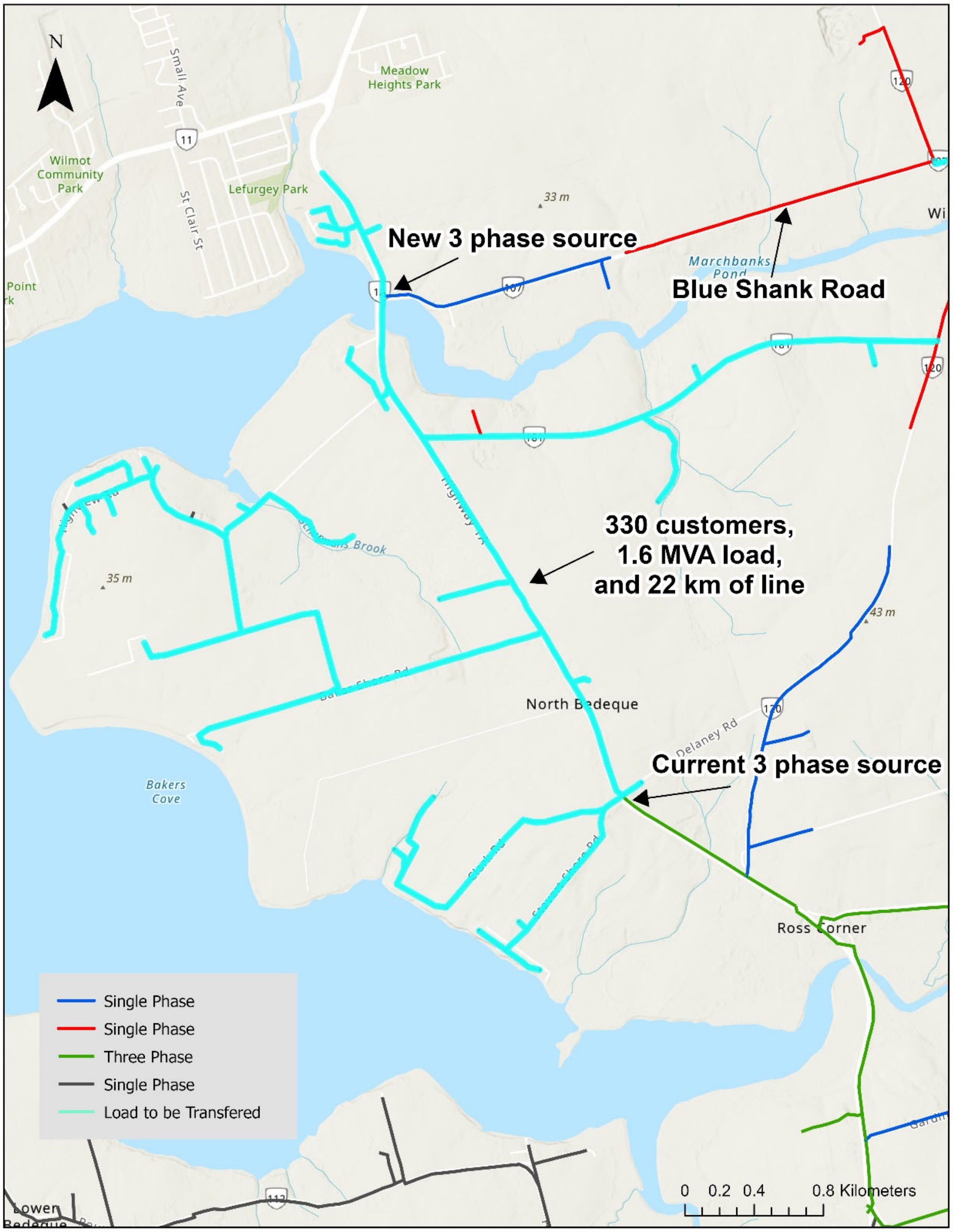


*Figure 2*
*Scope of load transfer from Bedeque feeder (AB33127) to Norboro feeder (KN80700)*

# APPENDIX K

## Single and Three Phase Line Rebuilds Description and Justification

**Title:** Alberton to Elmsdale

**Location:** Alberton and Elmsdale, PE

**Line Type:** Distribution – Three Phase

**Distance:** 4.75 kilometres ("km")

**Amount:** $1,673,000

## Project Description

This three phase rebuild project will replace a 4.75 km section of line AL00261 and AL03066 along the Dock Road (Route 150), starting near civic address #11 Dock Road (Dock Road and Church Street intersection) and ending near civic address #970 (Dock Road and Western Road intersection), as shown in Figure 1. The line is operated at 12,470 volts and is connected to the Alberton substation. There are 459 customers fed from these lines.

## Justification

The primary justification for the project is that these sections of AL00261 and AL03066 are at end of life, with examples of aged, deteriorated and non-standard assets shown in Figures 2 and 3. There are approximately 75 poles along the project route with 30 of them (40 per cent) being aged eastern cedar poles in poor condition. The condition of the conductor also puts it at an elevated risk of failure during storm conditions and, should failure occur, repairs will be more challenging and time consuming, which impacts reliability. Customers fed from AL00261 have experienced 2,763 customer outage hours in the last five years, and customers fed from AL03066 have experienced 5,338 customer outage hours in the last five years.

The project is justified based on the obligation to provide safe and adequate service to customers. For the reasons provided, the project is necessary and cannot be deferred.

## Costing Methodology

A breakdown of the budget for the Alberton to Elmsdale line rebuild project is shown in Table 1.

| TABLE 1<br>Breakdown of Proposed Budget<br>Alberton to Elmsdale Line Rebuild | |
|---|---|
| **Description** | **Budget** |
| Material | $ 297,000 |
| Contractor Labour | 1,167,000 |
| Internal Labour and Transportation | 209,000 |
| **TOTAL** | **$ 1,673,000** |

**Construction**

The existing conductor is a mixture of #4 ACSR (rated for 140 amps) and #2 smooth body (rated for 180 amps) and will be replaced with 477 Cosmos (rated for 584 amps) to bring the line to current standards. Construction for this rebuild will be labour intensive, due to several factors including extra safety precautions required for working around deteriorated #2 smooth body conductor, the location of the line relative to the roadside making it difficult to access, the condition of eastern cedar poles that cannot be leaned for safe construction clearances, and the large quantity of service attachments on the main line. The line will be rebuilt on the same side of the road to utilize existing service poles that are in good condition and do not require replacement.

A permit from the Department of Transportation and Infrastructure will be required and traffic control will be necessary for this project as vehicle speed is high on this road.

Construction is scheduled to begin in the second quarter of 2025, with 4 crews working for 15 weeks to complete the project.

**Alternatives**

There are no alternatives to this project. The section of line proposed for rebuild is at the end of its life and requires replacement.

**Future Commitments**

This is not a multi-year project.

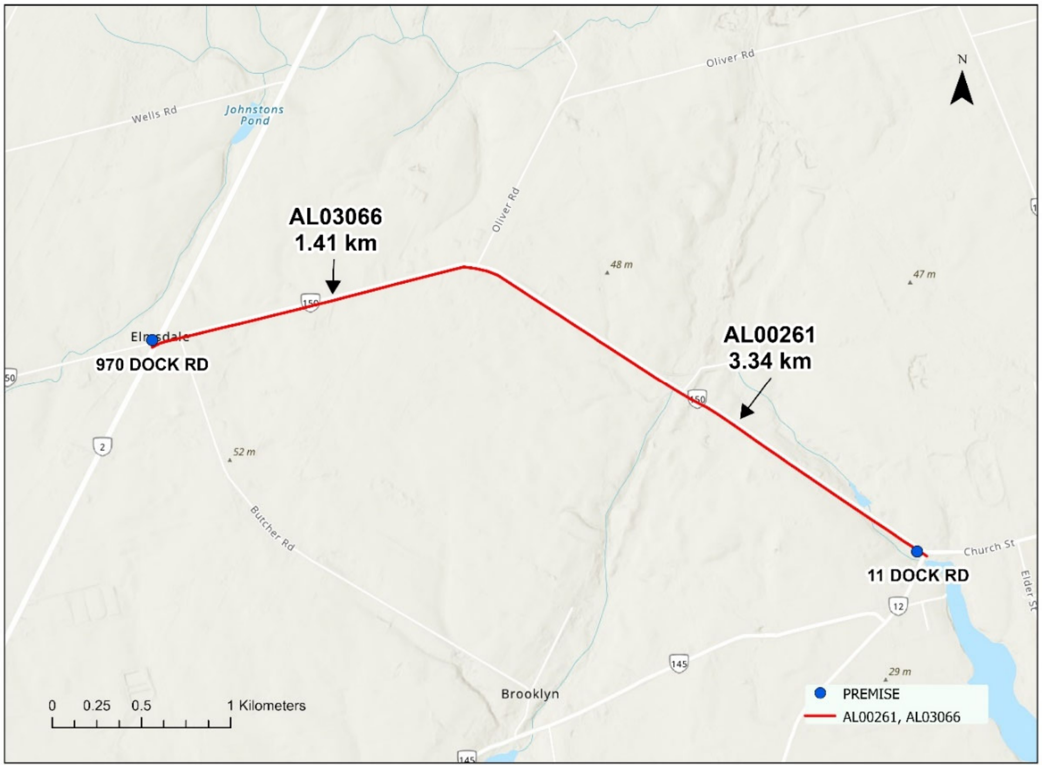


*Figure 1*
*Scope of the 4.75 km Alberton to Elmsdale line rebuild project, Alberton, PE*

*Figure 2*
*Deteriorated pole*

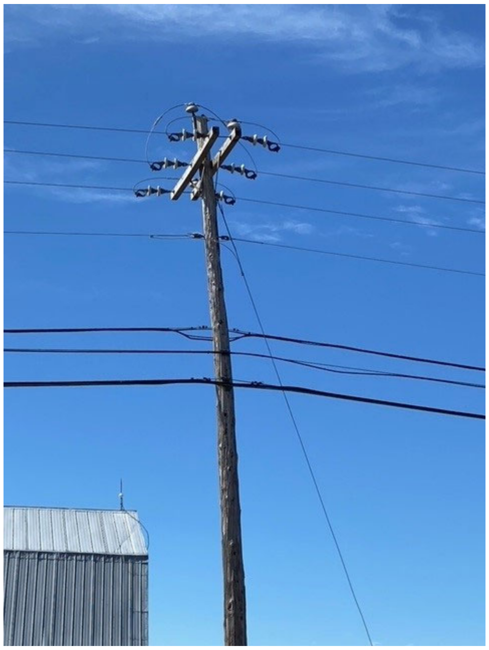

*Figure 3*
*Porcelain bell insulators*

**Title:** Keppoch Road

**Location:** Stratford, PE

**Line Type:** Distribution – Three Phase

**Distance:** 1.25 km

**Amount:** $699,000

**Project Description**

This project is a three phase rebuild to replace a 1.25 km section of line CR44492 along the Keppoch Road, starting near civic address #1 (Stratford Road intersection) and ending near civic address #58, as shown in Figure 4. The line is operated at 12,500 volts and is connected to the Crossroads substation. There are 250 customers fed from this line.

**Justification**

The primary justification for the project is that this section of CR44492 is at end of life, with examples of aged, deteriorated and non-standard assets shown in Figures 5 to 7. There are approximately 26 poles along the project route in poor condition. Customers fed from CR44492 have experienced 3,204 customer outage hours in the last five years.

The project is justified based on the obligation to provide safe and adequate service to customers. For the reasons provided, the project is necessary and cannot be deferred.

**Costing Methodology**

A breakdown of the budget for the Keppoch Road line rebuild project is shown in Table 2.

**TABLE 2**
**Breakdown of Proposed Budget**
**Keppoch Road Line Rebuild**

| Description | Budget |
|---|---|
| Material | $ 68,000 |
| Contractor Labour | 503,000 |
| Internal Labour and Transportation | 128,000 |
| **TOTAL** | **$ 699,000** |

**Construction**

The existing conductor, which is a mixture of #4 Swan (rated for 140 amps) and 2/0 Quail (rated for 270 amps), will be replaced with 477 Cosmos (rated for 584 amps) to bring the line to current standards and to accommodate future load growth. The line will be rebuilt on the same side of the road to utilize existing main line and service poles that are in good condition and do not require replacement.

A permit from the Department of Transportation and Infrastructure will be required and traffic control will be necessary for this project as vehicle speed is high on this road.

Construction is scheduled to begin in the second quarter of 2025, with 4 crews working for 6 weeks to complete the project.

**Alternatives**

There are no alternatives to this project. The section of line proposed for rebuild is at the end of its life and requires replacement.

**Future Commitments**

This is not a multi-year project.

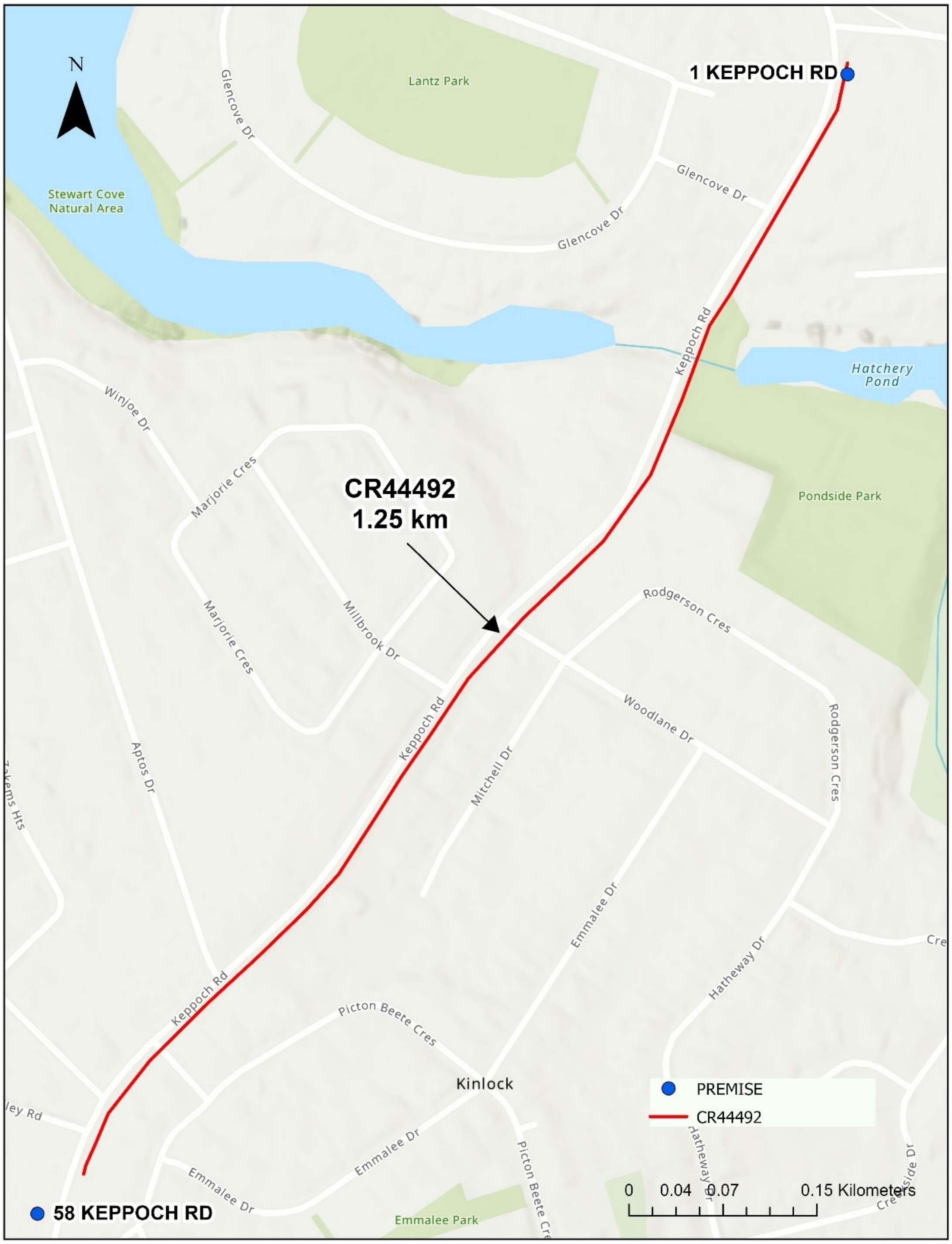


*Figure 4*
*Scope of the 1.25 km Keppoch Road line rebuild, Stratford, PE*

*Figure 5*
*Deteriorated pole with porcelain bell insulators*

*Figure 6*
*Deteriorated pole*

*Figure 7*
*Inadequate neutral spacing for upgrading transformers*

# APPENDIX L

## Distribution Inspection Deficiencies


*Figure 1*
*Padmount transformer broken blast wall*

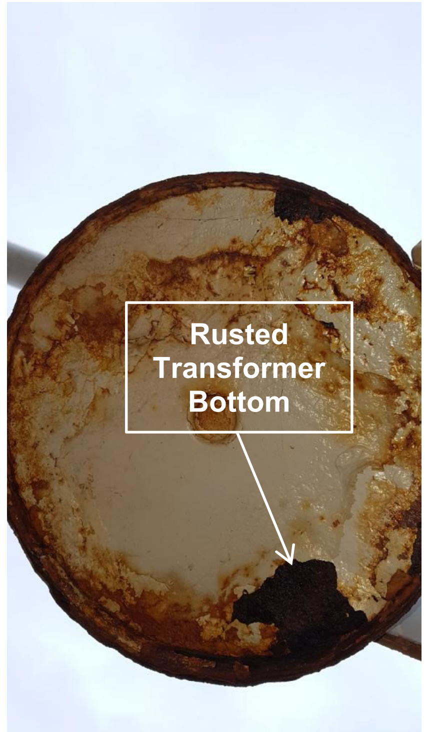


*Figure 2*
*Bottom of rusted pole top transformer*

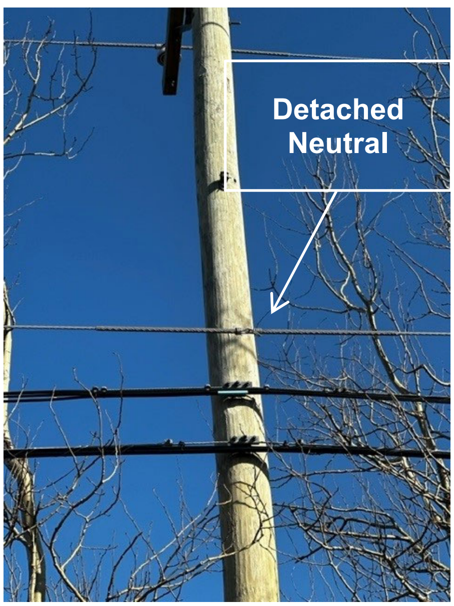


*Figure 3*
*Neutral detached from pole*

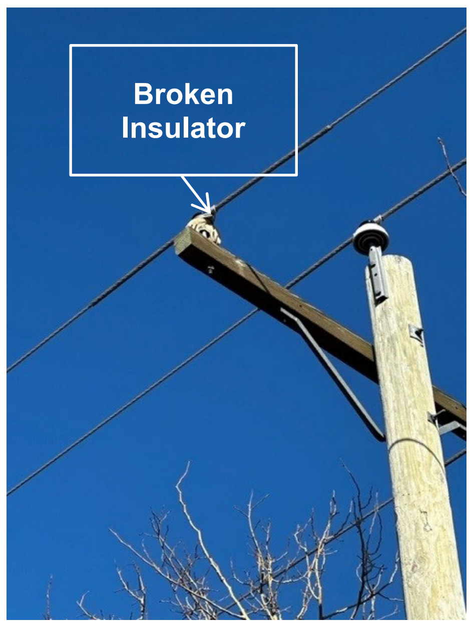


*Figure 4*
*Broken insulator*

# APPENDIX M

## Climate Change Adaptation Strategy

A REPORT ON MARITIME ELECTRIC'S

# CLIMATE CHANGE ADAPTATION STRATEGY

*Spring 2024*

Sustainable Electricity Leader

MARITIME ELECTRIC A FORTIS COMPANY

*This report was made possible with financial support from the Government of Prince Edward Island's Climate Challenge Fund*

# LAND ACKNOWLEDGEMENT

We respectfully acknowledge that the land upon which Maritime Electric operates is unceded Mi'kmaq territory. Epekwitk, Mi'kma'ki is covered by the historic Treaties of Peace and Friendship. We pay our respects to the Indigenous Mi'kmaq People, who have occupied this Island for over 12,000 years; past, present and future.

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# EXECUTIVE SUMMARY

Maritime Electric Company, Limited ("Maritime Electric") is a fully integrated electric utility, owning and operating components of the electricity generation, transmission and distribution systems that serve over 89,000 customers across Prince Edward Island ("PEI"). Since 1918, Maritime Electric has served PEI's energy needs with safe, reliable and increasingly cleaner electricity. In recent years, several extreme weather events, including Hurricane Dorian (2019) and Hurricane Fiona (2022), resulted in record-breaking impacts to Maritime Electric's electrical infrastructure. The intensity and frequency of extreme weather events are expected to increase in the future due to climate change. Maritime Electric is committed to plan for and adapt to the changing regional climate to maintain reliable electricity service for customers.

After Hurricane Dorian impacted PEI in 2019, Maritime Electric began planning for climate change adaptation by assessing climate impacts, evaluating climate change projections, calculating climate change risks and developing adaptation strategies.

In 2022, Maritime Electric completed a Climate Change Risk Assessment ("Risk Assessment"). The Risk Assessment included the evaluation of climate hazards and their potential impact on Maritime Electric's infrastructure, up to the year 2070. A summary of the high risks impacting Maritime Electric's infrastructure is provided below:[1]

- Extreme minimum temperatures are associated with high risks to the combustion turbines.
- Extreme maximum temperatures are associated with high risks to transmission and distribution substation power equipment.
- Ice storm/freezing rain events are associated with high risks to overhead transmission and distribution lines, towers, and structures.
- Hurricanes and tropical storms are associated with high risks to overhead transmission lines on wood structures, transmission substation power equipment, overhead distribution lines and substation buildings, distribution substation power equipment, communication fibre systems, and the cable oil buildings in Richmond Cove and Murray Corner.
- Extratropical storms (e.g., Nor'easters) are associated with high risks to overhead transmission and distribution lines and structures, transmission substation power equipment, and the communication fibre system.
- Various climate hazards are associated with high risks to human resources.

This Climate Change Adaptation Strategy ("Adaptation Strategy") report builds on the results of the Risk Assessment to further define, evaluate and prioritize climate change adaptation strategies. The Adaptation Strategy includes 17 strategies, which are categorized in four adaptation focus areas:

[1] Stantec Consulting Ltd. 2022. PIEVC Assessment for Maritime Electric Company Ltd. Charlottetown: Maritime Electric Company, Ltd.

1. Design: infrastructure design or construction modifications to increase the ability to withstand the impacts of extreme weather events.
2. Operations: changes to operational practices that will help improve Maritime Electric's effectiveness at identifying and resolving vulnerabilities to extreme weather events.
3. Resiliency: methods to reduce the impacts on customers from infrastructure damage following extreme weather events.
4. Employee Health and Safety: procedures to ensure the health and safety of Maritime Electric employees and contractors that are exposed to extreme weather events.

Maritime Electric developed and evaluated action items for each of the 17 adaptation strategies. Some of the adaptation strategies were successfully implemented in 2023, and others are ongoing or planned for the future. Maritime Electric's Sustainability Department is responsible for monitoring and reporting on the implementation of the Adaptation Strategy and associated action items across Maritime Electric's departments. The Adaptation Strategy requires continued review and updates as new climate science emerges and physical climate change risks are mitigated by Maritime Electric's adaptation efforts.

# BACKGROUND

Maritime Electric is a fully integrated electric utility, owning and operating components of the electricity generation, transmission and distribution systems that currently serve over 89,000 customers across PEI. Maritime Electric's grid infrastructure includes 28 substations, three combustion turbine generators with a combined capacity of 90 megawatts ("MW"), over 6,600 kilometres ("kms") of transmission and distribution lines, and over 127,000 utility poles. Maritime Electric also maintains and operates the four 138 kilovolt ("kV") subsea cables that connect to New Brunswick, which are owned by the Government of PEI.

Since 1918, Maritime Electric has served PEI's energy needs with safe, reliable and increasingly cleaner electricity. Maritime Electric is a subsidiary of Fortis Inc. ("Fortis"), a diversified holding company based in St. John's, Newfoundland, and is regulated by the Island Regulatory and Appeals Commission ("IRAC") operating under the provisions of the *Electric Power Act* and the *Renewable Energy Act*. Electricity is sourced from: imports from New Brunswick Electric Power Corporation ("NB Power") through subsea cables between New Brunswick and PEI; Island wind and solar farms through contracts with the PEI Energy Corporation; Point Lepreau Nuclear Generating Station through a contractual entitlement with NB Power; small renewable energy generators through net metering agreements with customers; and Maritime Electric's combustion turbine generators. The primary use of the combustion turbine generators is to supply energy in times of curtailment from off-island energy suppliers or during transmission line outages on PEI or on the mainland.

## Climate Change Mitigation and Adaptation

Maritime Electric's approach to climate change includes mitigation and adaptation. Climate change mitigation tackles the causes of climate change directly by reducing the amount of GHG emissions, notably carbon dioxide, released into the atmosphere or by increasing the capacity to sequester atmospheric carbon dioxide. Climate change adaptation evaluates the future impacts of climate change and takes actions to reduce its impact towards human activities. In the electricity sector, mitigation means decreasing reliance on oil, natural gas, coal, and other fossil fuels for electricity generation, and adaptation means building a strong and resilient electrical grid that can withstand the impacts of climate change. Adaptation measures alone are not sufficient to manage climate change and must serve as a complement to mitigation efforts.

Climate change mitigation efforts have been underway at Maritime Electric's Charlottetown Thermal Generating Station for the past decade. In 2022, Maritime Electric decommissioned the generating station, which eliminated the remaining on-Island heavy-fuel oil generating capacity and represents Maritime Electric's most significant effort to date to reduce GHG emissions. Current Scope 1, Scope 2 and Scope 3 emission inventories and performance is verified by a third-party and published in Maritime Electric's annual Sustainability Report.[2] Maritime Electric's target is to reduce GHG emissions by 55 per cent by

[2] Maritime Electric's annual Sustainability Reports are available at: maritimeelectric.com/sustainability

2030, compared to 2019 levels. Maritime Electric's grid is already 85 per cent clean, but to reach the target Maritime Electric estimates that approximately 100 MW of additional wind energy and 120 MW of additional solar energy is required by 2030, compared to 2022 levels.[3,4]

## Planning for Climate Change

After Hurricane Dorian impacted PEI in 2019, Maritime Electric initiated a Climate Change Risk Assessment to evaluate the long-term risks of climate change towards the electrical system. Maritime Electric received funding from the Government of PEI's Climate Challenge Fund and engaged Stantec Consulting Ltd. ("Stantec") to help complete the Risk Assessment, which studied current and future climate risks towards Maritime Electric's infrastructure and identified potential climate change adaptation strategies. The Risk Assessment followed the Public Infrastructure Engineering Vulnerability Committee Protocol, an evidence-based approach to assessing climate change risks developed by Engineers Canada. The results of the assessment demonstrate that risks associated with extreme climate events will increase in the future, and that climate change adaptation is required to manage these risks. Also included in the report were potential preliminary adaptation strategies for the high risks identified, each of which varies in complexity and cost.

In 2023, Maritime Electric received additional funding through the Government of PEI's Climate Challenge Fund to complete this Adaptation Strategy.

[3] 85 per cent clean electricity is based on 2022 data.

[4] Other combinations of wind and solar are also possible.

# METHODOLOGY

Maritime Electric's climate change adaptation approach follows a four-step process, as shown in Figure 1. Steps 1 to 3 were completed in 2022 as part of Maritime Electric's Risk Assessment and Step 4 consists of this Adaptation Strategy report. Maritime Electric intends to repeat the four-step process approximately every five years to re-evaluate climate change risks as new climate data and information becomes available. The four-step process is described in more detail as follows.

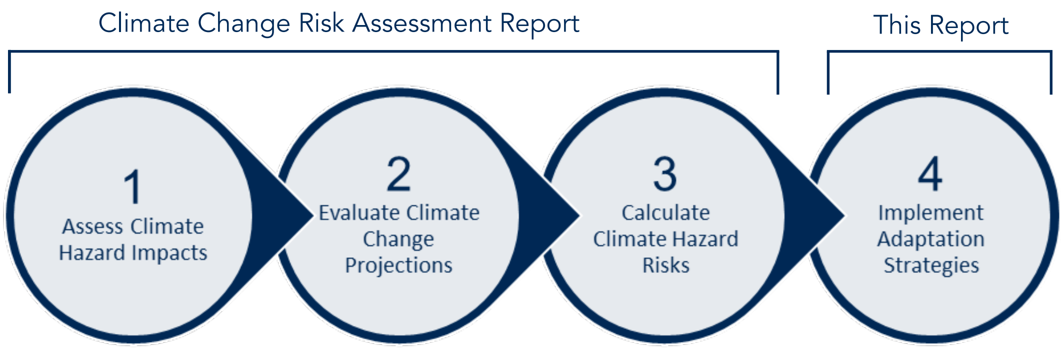


*Figure 1: Maritime Electric Climate Change Adaptation Process*

## Step 1: Assess Climate Hazard Impacts

### Infrastructure Identification

Identify infrastructure owned by Maritime Electric to be evaluated in the risk assessment such as transmission and distribution lines, substations, combustion turbines and select buildings. Identify infrastructure owned by third parties that could impact Maritime Electric's operations such as the four subsea cables and associated equipment, transmission lines and equipment from Memramcook to Murray Corner and Cape Tormentine that supply the subsea cables, and on-Island wind and solar farms. Include human resource personnel and contractors as part of the evaluation.

A map of Maritime Electric's service territory and significant infrastructure identified in the 2022 Risk Assessment is shown in Figure 2.[5]

[5] Infrastructure located in New Brunswick and owned by NB Power is not shown.

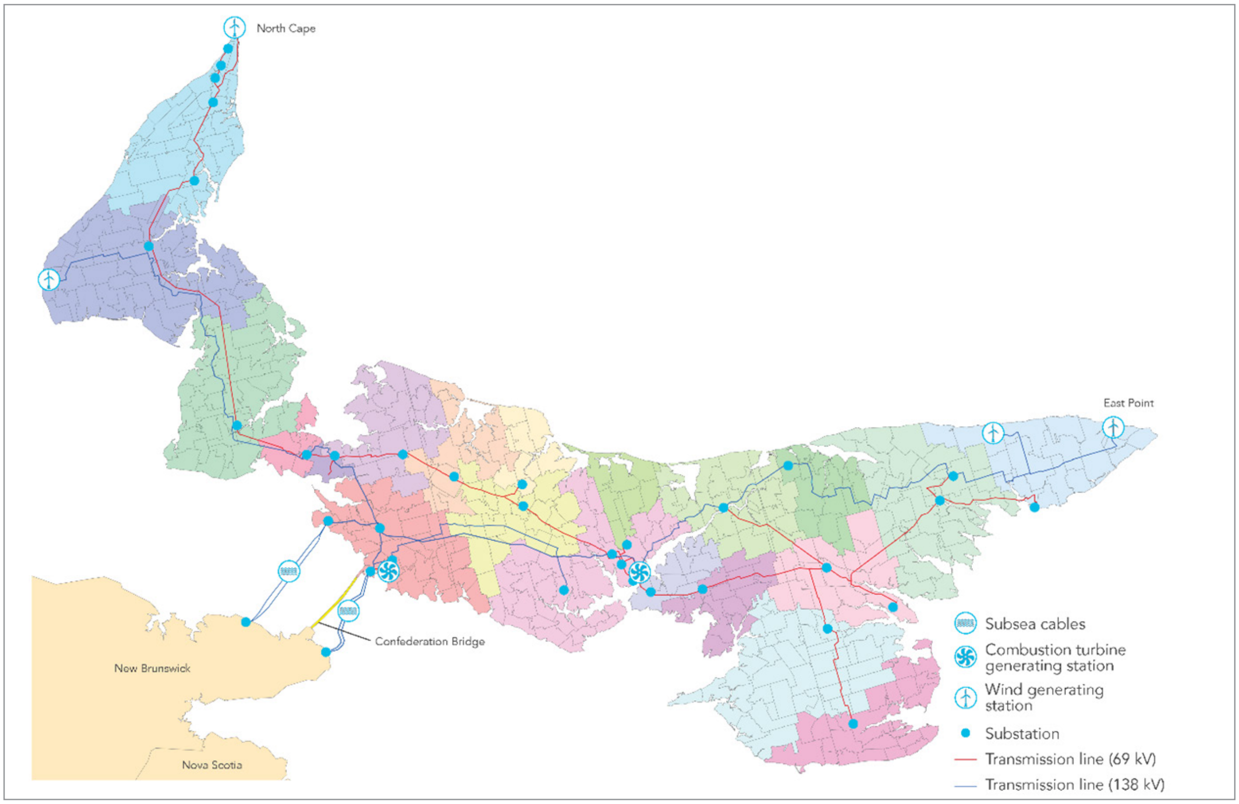


*Figure 2: Maritime Electric Infrastructure Map (2023)*

## Consequence Scoring

Evaluate the potential impacts (i.e., consequence) of several climate hazards towards the identified infrastructure by utilizing criteria aligned with Maritime Electric's Enterprise Risk Management Framework. The categories used in the 2022 Risk Assessment to assess the impact of climate hazards included:[6]

- Physical System Effects: physical disruptions to transmission, distribution, or other assets.
- Operations and Maintenance Deployment: personnel and/or resources required to address disruptions to operations.
- Load Restoration: the time required to restore electrical service to customers during an outage event.
- Financial Loss: restoration costs to address consequence (e.g., cost of asset repair or replacement).
- Health and Safety of Personnel: reduced work capacity or injuries related to climate events.

The consequence of climate hazards was scored based on the consequence scoring criteria shown in Table 1.

[6] Stantec Consulting Ltd. 2022. PIEVC Assessment for Maritime Electric Company Ltd. Charlottetown: Maritime Electric Company, Ltd.

*Table 1: Climate Hazard Consequence Scoring Criteria*[7]

| Score | Description | Criteria | | | | |
|---|---|---|---|---|---|---|
| | | Physical System Effects | Operations and Maintenance (Resources) | Load Restoration | Financial Loss | Health and Safety of Personnel |
| 1 | Very Low | Routine day-to-day trouble | Impacts can be managed by Energy Control Centre (ECC) and available Customer Service Utility Persons | Restoration of affected load generally within 3 hours | <$100,000 | Routine operations |
| 2 | Low | Multiple power lines and facilities affected | Impacts can be managed with available resources (i.e., personnel, material and equipment). Customer Service Representatives ("CSRs") may be required. Personnel overtime may be required. | Restoration of affected loads more than 3 hours and up to 24 hours | $100,000 - $300,000 | Potential for minor injury (e.g., dehydration, sprained joints/strained muscles) |
| 3 | Moderate | Multiple power lines and facilities affected possibly including transmission lines | Additional Maritime Electric resources and/or local contractors required. CSRs required. Combustion turbine operators may be required. Personnel overtime required. | Restoration of affected loads more than 24 hours and up to 3 days | $300,000 - $500,000 | Potential for moderate injury (e.g., heat exhaustion, broken bone, frost bite) |
| 4 | High | Multiple power lines and facilities affected including transmission lines or substations. Possible rolling blackouts. | All Maritime Electric resources and local contractors utilized. CSRs required. Combustion turbine operators required. Extensive personnel overtime required. | Restoration of affected loads more than 3 days and up to 7 days | $500,000 - $1,000,000 | Potential for major injury (e.g., heat stroke, loss of limb) |
| 5 | Very High | Multiple power lines and facilities affected including multiple transmission lines or multiple substations. Possible loss of equipment with long lead times. Possible island-wide blackout. | All Maritime Electric resources and local contractors utilized, and off-island contractors (mutual aid) required. CSRs required. Combustion turbine operators required. Extensive personnel overtime required. | Loads not restored within 7 days | >$1,000,000 | Potential for loss of life |

[7] Stantec Consulting Ltd. 2022. PIEVC Assessment for Maritime Electric Company Ltd. Charlottetown: Maritime Electric Company, Ltd.

# Step 2: Evaluate Climate Change Projections

## Climate Projections

Identify future climate conditions (i.e., projections) for each climate hazard including temperature, precipitation, wind and other complex climate hazards, to determine the probability of occurrence within different regions. As part of the 2022 Risk Assessment, Stantec developed climate projections using downscaled Global Climate Models. Climate projections were based on the Intergovernmental Panel on Climate Change's Representative Concentration Pathway ("RCP") 8.5 and RCP 4.5 up to the 2070s period.[8] RCP 8.5 was used for the risk analysis because it is the most widely used RCP for climate change risk assessments and represents the potential worst-case scenario. Climate projections were completed for Western, Central and Eastern PEI, as well as Northeastern New Brunswick for NB Power infrastructure; however, the results did not show material differences in climate projections between the regions.

## Probability Scoring

Evaluate the climate change projections using a probability scale. The scale used for the 2022 Risk Assessment is shown in Table 2.

*Table 2: Climate Hazard Probability Scoring Scale*[9]

| Probability Score | Qualitative Descriptor | Description | Probability (p) of Occurring per Year |
|---|---|---|---|
| 1 | Rare | Very unlikely or rare change that event will occur annually | $p \leq 5\%$ |
| 2 | Unlikely | Remote chance that event will occur annually | $5\% < p \leq 35\%$ |
| 3 | Possible | Probable chance that event will occur annually | $35\% < p \leq 65\%$ |
| 4 | Likely | Likely that event will occur annually | $65\% < p \leq 95\%$ |
| 5 | Almost Certain | Almost certain that event will occur annually | $95\% < p$ |

[8] Representative Concentration Pathways represent GHG emission concentration trajectories in the atmosphere, which form the basis of climate models.

[9] Stantec Consulting Ltd. 2022. PIEVC Assessment for Maritime Electric Company Ltd. Charlottetown: Maritime Electric Company, Ltd.

# Step 3: Calculate Climate Hazard Risks

## Risk Assessment

Combine the probability scores of each projection with the consequence scores for infrastructure impacts to calculate overall climate change risk rankings for each climate hazard, categorized as low, medium or high. The risk matrix used in the 2022 Risk Assessment is shown in Table 3.

*Table 3: Risk Matrix for the Climate Change Risk Assessment*[10]

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Probability Score** | **Almost Certain** | **5** | 5 | 10 | 15 | 20 | 25 |
| | **Likely** | **4** | 4 | 8 | 12 | 16 | 20 |
| | **Possible** | **3** | 3 | 6 | 9 | 12 | 15 |
| | **Unlikely** | **2** | 2 | 4 | 6 | 8 | 10 |
| | **Rare** | **1** | 1 | 2 | 3 | 4 | 5 |
| | | | **1** | **2** | **3** | **4** | **5** |
| | | | **Very Low** | **Low** | **Medium** | **High** | **Very High** |
| | | | **Consequence Score** | | | | |

| | | | |
|---|---|---|---|
| **Risk Levels:** | **Low** | **Medium** | **High** |

## Results

The 2022 Risk Assessment identified several climate hazards that pose a high risk to Maritime Electric's infrastructure and human resources, including changes in temperature, precipitation, high wind, ice storms, hurricanes and extratropical storms. Various climate hazards in New Brunswick including ice storms, freezing rain, hurricanes, extratropical storms, and lightning were also identified as posing high risks to Maritime Electric. A summary of the 2022 Risk Assessment results is shown in Table 4.

[10] *Stantec Consulting Ltd. 2022. PIEVC Assessment for Maritime Electric Company Ltd. Charlottetown: Maritime Electric Company, Ltd.*

*Table 4: Summary of Climate Change Risk Assessment Results*[11]

| Climate Hazards | Future Projections | Maritime Electric Impacts |
|---|---|---|
| High daily average temperature | ↑ | • High risks towards human resources working outdoors (e.g., dehydration and heat stroke) |
| Extreme maximum temperature | ↑ | • High risks towards substation power equipment that requires cooling (e.g., transformers)<br>• High risks towards human resources working outdoors (e.g., dehydration and heat stroke) |
| Heat waves | ↑ | • High risks towards human resources working outdoors (e.g., dehydration and heat stroke) |
| Extreme minimum temperature | ↓ | • High risks towards combustion turbines required to operate during cold temperatures<br>• High risks towards human resources working outdoors (e.g., frost bite) |
| Freeze-thaw cycles | ↓ | • No high risks identified<br>• Medium risks towards infrastructure with concrete foundations |
| High winds | ↑ | • High risks towards overhead transmission, distribution and fibre communication lines for gusts above 130 km/h |
| Hurricanes | ↑ | • High risks towards overhead transmission, distribution and fibre communication lines<br>• High risks towards substation power equipment and buildings<br>• High risks towards New Brunswick corridor infrastructure<br>• High risks towards human resources working outdoors |
| Extratropical storms | ↑ | • High risks towards overhead transmission, distribution and fibre communication lines<br>• High risks towards substation power equipment and buildings<br>• High risks towards New Brunswick corridor infrastructure<br>• High risks towards human resources working outdoors |
| Tornadoes | ↑ | • No high risks identified due to low probability<br>• Medium risks identified towards infrastructure and human resources (see list above for hurricanes) |

[11] *Stantec Consulting Ltd. 2022. PIEVC Assessment for Maritime Electric Company Ltd. Charlottetown: Maritime Electric Company, Ltd.*

| Climate Hazards | Future Projections | Maritime Electric Impacts |
|---|---|---|
| Sea level rise | ↑ | • No high risks identified<br>• Medium risks towards infrastructure near the coast |
| Storm surge | ↑ | • No high risks identified<br>• Medium risks towards the Charlottetown Generating Station substation and infrastructure accessibility near the coast |
| Lightning | ↑ | • High risks towards New Brunswick corridor infrastructure<br>• High risks towards human resources working on the electrical system |
| Extreme rainfall | ↑ | • No high risks identified<br>• Medium risks towards underground infrastructure (e.g., underground vaults and chambers) |
| Ice storms | → | • High risks towards overhead transmission and distribution lines<br>• High risks towards New Brunswick corridor infrastructure<br>• High risks towards human resources due to poor driving conditions |
| Heavy snowfall | → | • No high risks identified<br>• Medium risks towards human resources due to driving conditions |
| Tree growth | ↑ | • Tree growth rates are expected to increase due to increased temperatures and humidity, longer growing seasons and increased precipitation |
| Wildfires | → | • No high risks identified due to low probability<br>• Medium risks towards overhead infrastructure and substations in densely wooded areas |

# Step 4: Implement Adaptation Strategies

## Strategies Identification

As part of the 2022 Risk Assessment, Maritime Electric identified several preliminary adaptation options for infrastructure that had high climate change risk scores. Since then, Maritime Electric has further refined and developed climate change adaptation strategies, which are included in the Adaptation Strategy. Maritime Electric focused on adaptation strategies that have the most potential to reduce climate change risks at a reasonable cost. The adaptation strategies are categorized based on four focus areas:

1. Design: infrastructure design or construction modifications to increase its ability to withstand the impacts of extreme weather events.
2. Operations: changes to operational practices that will help improve Maritime Electric's effectiveness at identifying and resolving vulnerabilities to extreme weather events.
3. Resiliency: methods to reduce the impacts towards customers of infrastructure damage following extreme weather events.
4. Employee Health and Safety: procedures to ensure the health and safety of Maritime Electric employees that are exposed to extreme weather events.

## Implementation

Maritime Electric will implement the adaptation strategies highlighted in this report through its existing planning and budgeting processes to support regulatory filings, which will require approval from IRAC. Maritime Electric's Sustainability Department is responsible for monitoring and reporting on the implementation of the adaptation strategies and associated action items. As adaptation strategies are implemented and the local climate changes, Maritime Electric will continue to monitor progress on completing adaptation strategies and their impact on reducing climate change risks. Maritime Electric intends to update its Risk Assessment, at a minimum, every five years to update climate change projections and impacts based on adaptation efforts completed.

# ADAPTATION STRATEGIES

This section provides details regarding Maritime Electric's 17 adaptation strategies, which are categorized in four focus areas:

1. Design: infrastructure design or construction modifications to increase its ability to withstand the impacts of extreme weather events.
2. Operations: changes to operational practices that will help improve Maritime Electric's effectiveness at identifying and resolving vulnerabilities to extreme weather events.
3. Resiliency: methods to reduce the impacts towards customers of infrastructure damage following extreme weather events.
4. Employee Health and Safety: procedures to ensure the health and safety of Maritime Electric employees that are exposed to extreme weather events.

Each adaptation strategy contains one or more action items, which are categorized based on progress as follows:

- Planned: actions that are pending regulatory approval or are planned for the future.
- Ongoing: actions that are continuously being applied.
- In progress: actions that are in progress for completion.
- Complete: actions that were identified in the Risk Assessment and since completed.

## Design

### Strategy 1 Update overhead line design standards and construction methods

Overhead line design is a critical aspect of the electrical distribution and transmission system. The effective planning, construction, and maintenance of overhead lines are essential for ensuring the reliable and safe delivery of electricity to customers. To achieve this, industry professionals adhere to comprehensive design standards and construction methods that encompass the entire expected useful life of overhead lines.

#### Action 1.1 Update overhead line design standards to reflect projected changes in the local climate (in progress)

Overhead line design standards consist of guidelines and specifications that engineers follow to ensure the infrastructure's quality, reliability, and safety. Design standards encompass elements such as conductor selection, structure design, insulating requirements, line clearance requirements and environmental considerations. Maritime Electric meets all required Canadian Standards Association ("CSA") standards related to line design and exceeds CSA standards for structure strength and clearances to ensure a robust system.[12] CSA's approach involves providing data that is geographically specific, acknowledging the diverse climate challenges faced by provinces, territories, and communities. However, CSA data is based on historical climate and does not necessarily consider local climate change impacts. Recently, CSA began encouraging electric utilities to design infrastructure based on local historical weather and projected climate change impacts. With the projected changes in the local climate, Maritime Electric is updating weather criteria and design standards to account for climate change projections within PEI's geographical region.

Maritime Electric uses PLS-CADD, a line design software from Power Line Systems, to design new lines and analyze existing ones. PLS-CADD uses non-linear design analysis, as required by CSA standards, for overhead line design. The software also integrates geospatial information, which enables users to work with current terrain data and ensures accurate modeling of overhead line routes. The software's 3D visualization capabilities enable engineers to visually assess transmission line designs on the landscape and identify potential limitations within a specific geographical area. PLS-CADD performs a range of engineering calculations, including sag and tension analysis, structural analysis of towers and poles, and clearance analysis to ensure line design and construction comply with safety standards and regulations. The software also simulates unique scenarios, such as broken wire scenarios, to ensure that structures are stable in the event of a failure. The design load and structural analyses consider factors such as wind, ice, temperature, conductor tension and more to ensure that overhead lines and structures can withstand forces produced by various environmental conditions.

In 2023, following the completion of the Risk Assessment, Maritime Electric engaged Stantec to provide detailed climate probability data. The data is being used to update Maritime Electric's climate parameters and criteria files for overhead line design standards using an evidence-based approach. The climate probability projections used to update Maritime Electric's climate parameters are provided in Appendix A: Stantec Climate Data. Given that the majority of Maritime Electric's infrastructure has an expected useful life of 50 years, Maritime Electric intends to use the 2070 1-in-50-year probability climate parameters to update its weather criteria and line design standards for new construction. Maritime Electric's intention is to update climate projections every five years and update climate design parameters accordingly.[13] A comparison of CSA standards and Maritime Electric's existing and updated climate parameters for weather modeling scenarios are shown in Table 5; weather parameters that have changed are shown in red.

[12] CSA Standard C22.3 No. 1:20 Overhead Systems

[13] The 2070 1-in-50-year climate parameters represent what is predicted to be a 1-in-50-year climate event in the 2070s. The probability of such an event occurring in the present day is lower than 1-in-50 years.

*Table 5: Comparison of Existing and Proposed Modeling Scenarios and Weather Parameters*

| Modeling Scenarios | Weather Parameters: Sustained wind speed (km/h) | Wind gusts[1] (km/h) | Radial ice accretion (heavy) (mm) | Extreme maximum temp. (°C) | Extreme minimum temp. (°C) |
|---|---|---|---|---|---|
| **CSA C22.3 Overhead Systems** | | | | | |
| Charlottetown | 108 | 142 | 12.5 | 35 | -31 |
| Souris | 114 | 150 | 12.5 | 35 | -28 |
| Summerside | 109 | 144 | 12.5 | 35 | -31 |
| Tignish | 118 | 155 | 12.5 | 36 | -32 |
| Maximum Values | 118 | 155 | 12.5 | 36 | -32 |
| **Maritime Electric Existing Scenarios** | | | | | |
| CSA Heavy (Wind & Ice) | 92 | - | 12.5 | - | - |
| Extreme Wind | 130 | - | - | - | - |
| Extreme Ice | 26.5 | - | 19 | - | - |
| Cold Uplift | - | - | - | - | -22 |
| Maximum Values | 130 | - | 19 | 40 | -25 |
| **Stantec Data** | | | | | |
| Baseline (1 in 50-year) | 127 | 172 | 35 | 32.7 | -32.0 |
| 2070s (1 in 50-year) | 130 | 176 | 18 | 37.3 | -23.2 |
| **Maritime Electric Proposed Scenarios** | | | | | |
| CSA Heavy (Wind & Ice) | **108** | **108**[2] | 12.5 | - | - |
| Extreme Wind | 130 | **176**[2] | - | - | - |
| Extreme Ice | 26.5 | - | 19 | - | - |
| Cold Uplift | - | - | - | - | **-25** |
| Maximum Values | 130 | **176**[2] | 19 | 40 | **-30** |

Table Notes:

1. Wind gusts are not specfically modelled in PLS-CADD.
2. Wind gust parameters shown were converted to sustained wind speeds using an appropriate ratio to simulate wind gust parameters.

## Action 1.2 Implement strategic line design standards to mitigate the risk of cascading transmission structures (planned)

Maritime Electric's transmission system, as shown in Figure 3, is composed of over 8,900 wooden or steel structures and over 750 kms of transmission lines. The transmission system interconnects and provides electrical supply to substations, where voltage is reduced for widespread distribution to customers. Damage assessment following Hurricane Fiona identified a significant number of trees that fell on transmission lines; however, only 10 transmission structures were damaged and required replacement. While Maritime Electric's transmission infrastructure suffered only minimal damage during Hurricane Fiona, outages on transmission lines can result in the loss of service to one or more substations, which deliver electricity to thousands of customers; therefore, the prevention of transmission-related outages is essential.

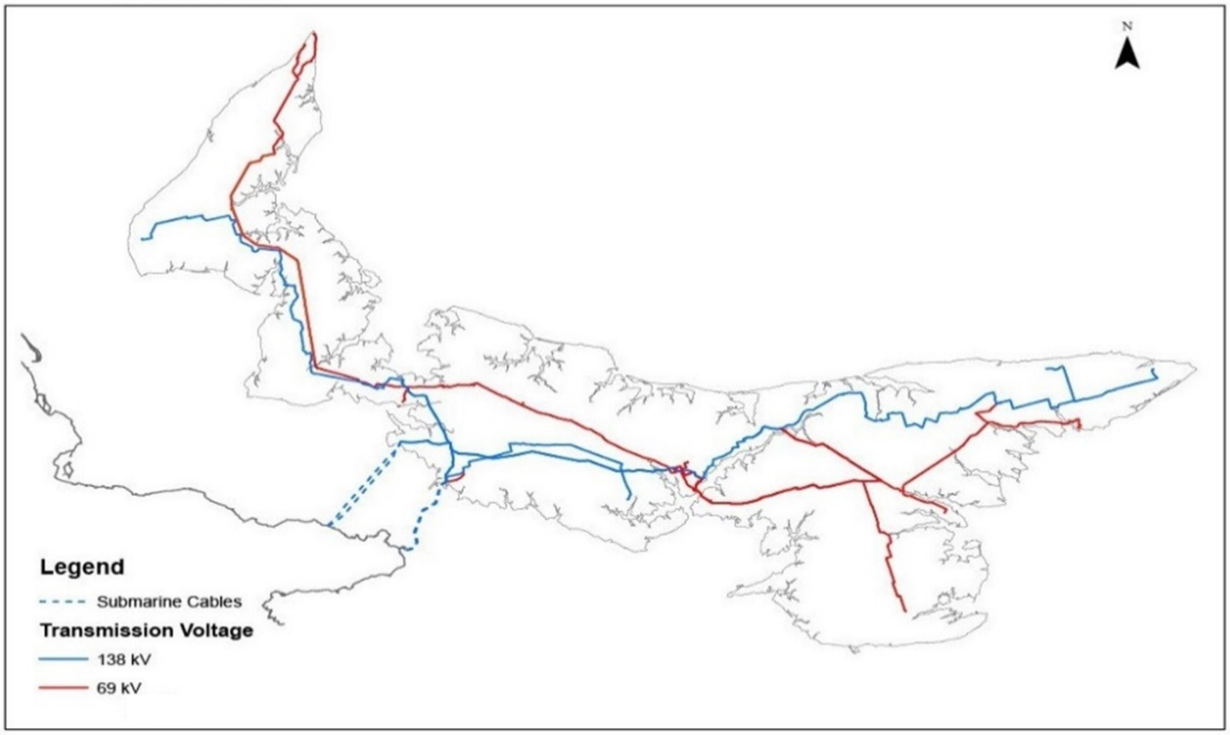


*Figure 3: Maritime Electric Transmission System*

Preventing cascading failures of transmission structures can be accomplished by installing additional guys and anchors to existing lines, a practice known as "storm guying."[14,15] Traditionally, guys and anchors are installed to support offset loads or angled structures, which stabilizes transmission and distribution structures. However, storm guying adds additional support to existing structures to significantly increase their resistance to dynamic loads from multiple directions and reduce the risk of cascading transmission structure failures. For basic structures, up to four additional guys can be installed, and for more complex structures, such as dead-ends and vertically framed structures, up to 12 guys may be required. An example of storm guying on one of Maritime Electric's transmission structures is shown in Figure 4.

[14] *Cascading refers to the failure of multiple structures in a sequence, where the failure of a single structure causes successive structures to fail.*

[15] *Guys are tensioned wires that anchor the top of a structure to the nearby ground at an angle.*


*Figure 4: Two-Way Storm Guys on Transmission Structure*

Another method that can prevent cascading impacts for transmission structure failures is to identify strategic locations on the transmission system to implement more robust line design standards. For example, the risk of cascading transmission structure failures can be reduced by adding double-dead-end structures, as opposed to tangent structures, at targeted locations.[16] Double-dead-end structures, as shown in Figure 5, include additional guying and anchoring, which helps stabilize and anchor the transmission line in the event of a cascading scenario. Examples of locations that may be targeted to reduce the risk of cascading impacts include:

- Line sections located in heavily treed areas;
- Line sections in areas that are commonly exposed to high wind; and
- Line sections with a significant number of consecutive tangent or light-angle structures.

A detailed analysis of the transmission system will be completed to identify transmission structures to implement strategic storm guying and more robust line design standards.

[16] *Tangent structures are poles sequenced in a straight line with minimal to no line angle. Double-dead-end structures are poles where a line turns at a large angle.*

*Figure 5: Double-Dead-End Light-Angle Structure*

### Action 1.3 Consider the use of more resilient pole structure materials in strategic areas (ongoing)

Maritime Electric and other electric utilities in Canada use primarily wood poles for their electrical system. Wood poles are sourced locally in Canada and are less expensive compared to other pole types, such as steel and composite poles. Poles are available in various heights and classes, depending on the application.[17] Pole height requirements are determined by CSA standards and based on the type of line, clearance requirements by voltage and the number of attachments on the pole (e.g., communication lines). Maritime Electric uses industry best practices and specialized line design software to determine the type, height and class of poles used throughout its electrical system.

Maritime Electric uses steel poles in some cases, such as river crossings, where wood poles cannot be installed. For example, transmission line T-2 utilizes steel poles along the Hillsborough Bridge between Charlottetown and Stratford. Steel poles can be stronger than wood poles but are more expensive and

[17] *Pole class refers to a pole's strength based on its ability to withstand horizontal loads and the class is selected based on Maritime Electric's design standards (see Action 1.1).*

less versatile. Additionally, adding lines and attachments is more complex and performing live line work is more challenging for steel poles compared to wood poles.

Wood poles are recognized as more environmentally friendly than other pole materials. A literature review conducted in 2017 of studies that performed life cycle assessments for various utility pole materials showed that wood poles typically have lower environmental impacts compared to other materials.[18] The literature review also showed variations in the useful life of poles amongst the 13 studies reviewed, but the majority assigned a consistent useful life of 50 to 60 years for wood, steel and composite pole materials. The literature review does not clearly demonstrate that a specific pole material has superior durability over others.

Maritime Electric will continue to follow CSA standards and use line design software to determine the appropriate pole material, size and class for various applications. The climate change data and line design software discussed in Action 1.1 will determine whether more steel or composite poles are used in certain applications based on the criticality of the line.

### Action 1.4 Consider the use of more resilient pole structure materials in strategic areas (ongoing)

Galloping is a naturally occurring phenomenon caused by the combination of ice formation on conductors and moderately strong crosswind.[19] Galloping generally occurs when steady perpendicular crosswind with low turbulence causes high amplitude vertical conductor oscillations; therefore, river crossings or areas near the shore with open exposure are more susceptible to galloping.[20] Frequent galloping for extended periods of time can weaken pole structures and conductor connections. In some instances, galloping can result in arcing between conductors and faults for three-phase lines.[21]

According to an Electric Power Research Institute research project conducted in 2005, there are three main methods to reduce the risk of galloping: ice removal, making lines tolerant to galloping and installing mechanisms that interfere with galloping.[19]

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[18] Nimpa, G. D., J. M. Njankouo, P. S. Ngohe-Ekam, and T. Tamo Tatiestse. 2017. "Life Cycle Assessment of Power Utility Poles – A Review." International Journal of Engineering Science Invention 6 (2): 16-32.

[19] Task Force B2.11.06. n.d. "State of the Art of Conductor Galloping: A Complementary Document to "Transmission Line Reference Book –Wind-Induced Conductor Motion Chapter 4: Conductor galloping," Based on EPRI Research project 792."

[20] Havard, D. G. 2007. Conductor Galloping: A Tutorial Presented at the IEEE ESMOL and TP&C Meeting. Las Vegas, January.

[21] Three-phase lines contain three conductors, each of which is referred to as a phase.

**Option 1: Removing ice from lines**

Removing ice from lines consists of de-energizing lines to physically remove the ice. Methods associated with removing ice are generally not practical because they require line outages, which can impact customers. Additionally, extreme galloping is typically not identified until after damage or a fault occurs.

**Option 2: Making lines tolerant to galloping**

Making lines tolerant to galloping includes designing lines to mitigate the impacts of galloping. Examples include shorter spans and increasing the strength of pole structures. Allowing for proper line clearances between phases can also prevent faults caused by galloping. Currently, Maritime Electric includes a CSA galloping scenario when performing design load analyses for new lines, which ensures lines can withstand the impacts of moderate galloping; however, extreme galloping or frequent galloping in the same area can cause fatigue failure on pole structures and components over time.

**Option 3: Adding mechanisms that interfere with galloping**

Adding mechanisms that interfere with galloping consists of adding physical devices to new or existing lines. Cost-effective solutions for adding physical devices to lines to prevent galloping exist, such as air-flow spoilers, that can interfere with the forces that cause galloping, thus reducing its amplitude and impacts. Air-flow spoilers, as shown in Figure 6, are helical devices widely used in the industry that attach to new or existing lines and change the aerodynamic profile of the line. The change in aerodynamic profile across the line interferes with the formation of ice surface formations that result in galloping. Currently, Maritime Electric successfully uses air-flow spoilers in some areas that are prone to galloping, such as on its transmission line T-2 along the Hillsborough Bridge between Charlottetown and Stratford and other river crossings.

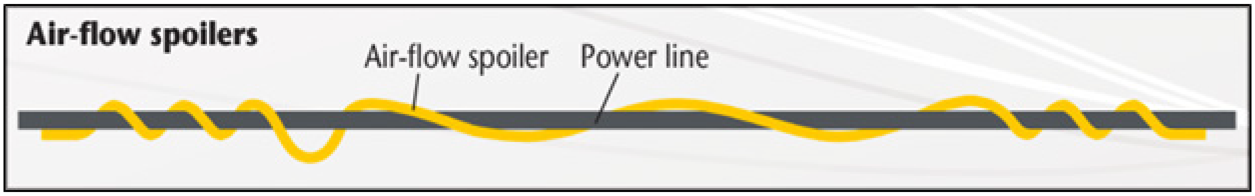


*Figure 6: Air-Flow Spoiler Diagram*[22]

Predicting where galloping will occur in advance is difficult because the phenomenon is impacted by several factors and is a function of the natural frequencies of the wire in the application; therefore, Maritime Electric will continue installing galloping prevention devices in areas where galloping is frequently observed. River crossings, for example, are more prone to galloping due to potential high crosswinds and long spans between poles.

[22] Kuiper, Jason. 2020. How does that work? Air-flow spoilers. December 28. https://oppdthewire.com/air-flow-spoilers-how-works/

### Action 1.5 Evaluate the strategic use of break-away devices for service lines (planned)

During Hurricane Fiona, over 2,000 Maritime Electric customers experienced damaged service masts.[23] Damage to service lines and masts is typically last to be repaired during major restoration events, as crews work to prioritize repairs to transmission and main distribution lines.[24] Damage to service lines and customer-owned service masts attached to buildings require a certified electrician to make repairs, which can further delay power restoration to the customer. A relatively new method of avoiding damage to service lines and service masts is to use break-away devices.

Break-away devices are components that attach to a power line and serve as a mechanical break-away point to separate the secondary line at the pole connection in the event that a tree falls on the line. Break-away devices can prevent damage to customer-owned service masts and reduce the risk of broken service lines. In the event that a tree falls on a service line, a break-away device would disconnect from the pole and fall to the ground. Using break-away devices for service lines has the following benefits:

- Service lines are disconnected at the pole, which safely de-energizes the service line before it falls;
- Break-away devices facilitate work for crews when manually disconnecting damaged service lines and opening cutouts to make service lines safe for tree removal by customers and prior to energizing main distribution lines; and
- Break-away devices utilize a quick-connect system, which may reduce the time required to reconnect customers.

Break-away devices are relatively new to the electric utility industry; therefore, their long-term effectiveness remains unknown. Maritime Electric is in the process of selecting break-away devices to test on service lines. The devices will be tested for their ease of installation and their effectiveness against minimizing damage to service lines and customer-owned service masts.

## Strategy 2 Perform strategic undergrounding of lines

Maritime Electric's transmission and distribution system consists of both overhead and underground lines, with the vast majority of the system consisting of overhead lines. Underground distribution lines are typically limited to urban areas to maintain clearances and for visual aesthetic purposes, whereas underground transmission lines are typically limited to substation duct banks. Maritime Electric permits its customers to supply and install their own underground secondary service, and Maritime Electric's personnel connect it to its facilities for energization. In new developments, such as new subdivisions, developers may choose to pay for the installation of underground primary lines, and customers can choose to install underground services from the underground primary lines.

The benefits of underground power lines include improved system reliability, improved visual aesthetic and reduced vegetation management requirements; however, underground power lines are significantly more expensive than overhead lines. Underground power lines can also have longer restoration times if

[23] *A service mast is an electrical component that connects overhead power lines to a building.*

[24] *Service lines are power lines that connect between a utility pole and the customer's premise.*

outages occur, are difficult to inspect, require outages when connecting new customers, are more difficult to upgrade for load growth and can be prone to flooding in coastal or low-lying areas. Additionally, communication line requirements can complicate the process of installing power lines underground because coordination is required with communication service providers during construction. For these reasons, installing power lines underground is not always a preferred solution to mitigate climate change risks, and should instead be considered on a case-by-case basis.

### Action 2.1 Develop a program to encourage the installation of underground service lines for customers (planned)

Currently, underground service lines are available as an optional facility as per Maritime Electric's Rates and General Rules and Regulations ("Rules and Regulations"). Customers can choose to install underground service lines, but the majority of customers select overhead service lines due to the prohibitive cost of burying service lines. Maritime Electric has evaluated the cost of converting existing high-voltage overhead infrastructure to underground and has determined that it would be expensive and would significantly impact customer rates. However, regulations in other jurisdictions with different regulatory models should be evaluated to identify opportunities to increase the attractiveness of underground service lines for new construction on a go-forward basis. Maritime Electric will evaluate options for changes to its Rules and Regulations to make underground service lines more economical for customers.

## Strategy 3 Use structural steel members for substation construction

Substations convert high voltage electricity from transmission lines to lower voltages for distribution to customers and are critical to the electrical system. Equipment failures in substations can result in prolonged outages that affect a large number of customers; therefore, it is important that they can withstand significant weather conditions. Due to their robust design, Maritime Electric's substations experienced limited impacts due to weather in the past and there was no significant damage to the substations during Hurricane Fiona.

Substation construction methods in the industry evolved throughout the years. Prior to 2017, Maritime Electric's 138 kV transmission substations were constructed using lattice steel structures (Figure 7) and concrete footings, while the distribution substations were constructed using wood poles and wood crossarms (Figure 8) because of its ease of installation and availability of materials. In 2017 and 2018, Maritime Electric constructed or refurbished three substations with wood poles and fiberglass crossarms (Figure 9). Wood crossarms deteriorate faster than wood poles; therefore, fiberglass crossarms were used to improve the lifespan of substation structures. In 2019, Maritime Electric began constructing its new and refurbished substations using structural steel members and concrete footings (Figure 10). The quantity of each substation type is shown in Table 6.

*Figure 7: Lattice Structure Substation*

*Figure 8: Wood Substation*

*Figure 9: Wood and Fibreglass Substation*

*Figure 10: Structural Steel Substation*

*Table 6: Maritime Electric Substations*

| Substation Type | Quantity |
|---|---|
| Lattice Steel | 4 |
| Structural Steel | 7 |
| Wood | 13 |
| Wood and Fibreglass | 3 |
| Wood and Structural Steel | 1 |
| **Total** | **28** |

### Action 3.1 Continue the construction of structural steel substations for all new and refurbished substations (ongoing)

Maritime Electric will continue to construct new substations and complete substation refurbishments using structural steel members, wherever possible. Structural steel members are more durable than lattice steel structures and less prone to structural deterioration. Structural steel members are also more physically stable than wood structures, which is beneficial in substations where several structures are interconnected to support equipment. The strength and durability of structural steel substations make them more resilient towards future extreme weather events, including high wind and ice storms. Structural steel substations also eliminate the potential wildfire fuel load that wood substations represent. Maritime Electric intends to construct all new substations and refurbish existing ones with structural steel due to its superior resilience towards climate events and increased clearances for the safety of personnel working in substations.

## Strategy 4 Complete a detailed evaluation of wildfire risk

When Maritime Electric completed its Risk Assessment, wildfire risk was deemed as a moderate risk.[25] However, since the assessment, there have been record-breaking wildfires across Canada, including those in neighbouring provinces of Nova Scotia and New Brunswick. These recent wildfires and downed trees from weather events demonstrate the need for increased wildfire planning and risk mitigation.

There are two types of wildfire risks for Maritime Electric: (1) the climate risk that a wildfire impacts Maritime Electric's infrastructure, which was deemed as moderate in the Risk Assessment; and (2) the business risk that Maritime Electric's infrastructure causes a wildfire, which was not assessed in the Risk Assessment but will be included in future evaluations (see Action 4.1). Maritime Electric must consider both of these risks as temperatures and the probability of heat waves increase due to climate change.

### Action 4.1 Complete a detailed evaluation of wildfire risks to identify risk mitigation strategies (planned)

Maritime Electric will complete a detailed evaluation of wildfire risk to evaluate the risk of Maritime Electric's infrastructure starting a wildfire and identify mitigation strategies to reduce them. The evaluation will include a review of risk mitigation strategies utilized in other jurisdictions. As part of the evaluation, Maritime Electric will also review transmission lines that traverse densely wooded areas and evaluate options for widening the right-of-way in those areas.[26] High-risk areas will be prioritized for widening.

[25] Wildfires received high consequence scores but the probability of them occurring on PEI was deemed as low.

[26] A right-of-way is a land area in which Maritime Electric has a legal right to pass over.

## Strategy 5 Ensure building structures are designed to withstand forces created by high wind

Maritime Electric owns several buildings, including storage facilities for tools and equipment, office buildings and substation control buildings. Substation control buildings, in particular, are critical infrastructure that ensure the efficient operation of a substation. Maritime Electric's new substation control buildings are designed by a licensed structural engineer according to the National Building Code of Canada. New buildings include concrete foundations, 2x6 walls, vertical roof truss bracing and roof truss hurricane anchors. The new control buildings also include industrial-grade exterior doors, steel roofs and steel siding. These features ensure that new control buildings can withstand extreme weather events. Substation control buildings are also inspected monthly to ensure there are no deficiencies, and buildings are repaired as required.

### Action 5.1 Conduct an evaluation of critical buildings to evaluate their effectiveness to withstand hurricane-force wind (planned)

Although Maritime Electric has not experienced significant damage to buildings from weather events in the past, the ability of older buildings to withstand hurricane-force wind is unknown. Maritime Electric will conduct a review of all substation buildings to evaluate their structural integrity and determine whether structural reinforcement or complete building replacement is required. The review will include visual inspections of the roof structures, exterior doors and windows for deficiencies. Based on the results of the building evaluations, Maritime Electric intends to add substation building retrofits to its existing Substation Modernization Program in order to increase resilience towards high wind.[27] Retrofit recommendations will be provided by a structural engineer, where applicable.

## Strategy 6 Complete a detailed flood risk analysis for the Charlottetown Generating Station site prior to installing new infrastructure

The Charlottetown Generating Station site, located near the Charlottetown Waterfront, has previously flooded during extreme rain and storm surge events. The site includes a steam plant building that is being demolished, an Energy Control Centre building, a substation, a combustion turbine generator, a water treatment building and a diesel fuel tank farm. In January 2000, flooding occurred in the basement area of the steam plant building, resulting in equipment needing to be elevated to prevent impacts from future flood events. During the January 2000 flooding event, other on-site infrastructure was not affected (the substation equipment is elevated on a steel structure). When Maritime Electric installed the combustion turbine generator on the site in 2005, it was designed and constructed at an appropriate elevation to withstand flooding impacts. A detailed flood risk study is recommended prior to installing new infrastructure to ensure that future sea level rise, storm surge and extreme rainfall will not impact the infrastructure.

[27] Maritime Electric's Substation Modernization Program is a reoccurring capital program that updates existing substations to meet current standards.

### Action 6.1 Complete a detailed flood risk assessment for the Charlottetown Generating Station site prior to new infrastructure being installed (planned)

In 2020, Maritime Electric completed an internal storm surge and flooding assessment of the Charlottetown Generating Station site, which included elevation measurements at various locations across the site. Maritime Electric will leverage the 2020 assessment by completing a detailed flood risk assessment for the site in the near future. A study specific to the site will ensure that future infrastructure is designed at an appropriate elevation or that flood mitigation measures are applied. The study will also help address any stormwater drainage deficiencies, if any. Maritime Electric plans to complete a flood risk study for the site prior to installing any additional infrastructure.

## Strategy 7 Implement flood mitigation measures

Maritime Electric has not experienced significant impacts from coastal flooding in the past; however, given PEI's coastal landscape and historical coastal erosion rates, future coastal flooding impacts are possible. In 2023, Maritime Electric added Coastal Hazards Information Platform ("CHIP") flood hazard data, provided by the Government of PEI, to its Geographic Information System ("GIS") mapping tools, as shown in Figure 11.[28] Maritime Electric is using the mapping tools to evaluate infrastructure flood risks for existing and new infrastructure.

*Figure 11: North Rustico 2020 Flood Hazard Map*

Transmission and distribution lines, including poles, can withstand occasional flooding depending on the severity. Substations and underground infrastructure, however, are more susceptible to flooding damage. Maritime Electric's infrastructure located in flood hazard areas include the substation located at the Charlottetown Generating Station (see Action 6.1) and several underground vaults located in downtown Charlottetown.

[28] A Geographic Information System is a computer system that displays and analyzes data based on its geographical location.

### Action 7.1 Use flood mapping tools to evaluate flood risks for existing and new infrastructure (in progress)

Maritime Electric will explore opportunities to evaluate flood risks for its existing infrastructure using GIS tools, including the CHIP flood hazard mapping tools provided by the Government of PEI. Maritime Electric intends to complete an analysis to identify areas where transmission lines, distribution lines and other infrastructure fall in the CHIP 2020 and 2050 flood hazard areas. The number of poles and kilometers of line in flood hazard areas will help Maritime Electric further evaluate its exposure to flood risk and prioritize flood risk mitigation work. Maritime Electric will also continue to use flood mapping tools when planning for and designing new infrastructure, such as new distribution lines, transmission lines and substations.

### Action 7.2 Continue to inspect underground vaults biennially (ongoing)

Maritime Electric maintains underground vaults as part of its underground distribution system located in downtown Charlottetown. Vaults are isolated underground enclosures that contain distribution equipment critical for the delivery of electricity to customers in the area. Equipment located in the vaults includes switching points for distribution feeders and transformers. Vaults can be at risk of flooding from storm surge or extreme rainfall events.

Maritime Electric inspects the vaults in Charlottetown biennially to evaluate their condition and the electrical equipment within them. Inspectors evaluate the condition of the concrete and take thermal images of the electrical equipment to identify hotspots. Inspectors also inspect the condition of transformer tanks, primary load-break elbows and secondary connections. If water is present in the vault, inspectors note the presence of water and evaluate whether the drainage system is functioning properly.[29]

Maritime Electric records vault inspection results using an Underground Facility Inspection Report. If the inspector identifies deficiencies during the inspection, maintenance items are created to address the deficiencies in a timely manner. Typical maintenance items include pumping water out of the vault and installing new submersible termination connections for primary, secondary and ground connections. In the past, the process of pumping out water on an annual basis has successfully prevented damage to electrical equipment located in vaults; however, the increased likelihood of extreme rain events due to climate change poses increased risks to vaults. As part of Maritime Electric's vault inspection enhancements, Maritime Electric will inspect vaults following extreme rain events and use the results to determine whether the installation of permanent submersible pumps or the relocation of infrastructure above ground is required for select vaults.

In 2023, Maritime Electric added data from the Government of PEI's CHIP to its GIS mapping tools. Figure 12 shows Maritime Electric's vaults in Charlottetown with the CHIP 2100 moderate-low flood hazard area. The King Street vault is located within 15 metres of a moderate-low flood hazard area and other vaults are located over 100 metres away from flood hazard areas. The CHIP data demonstrates that the likelihood of

[29] Only some of Maritime Electric's vaults contain drainage systems.

vaults flooding due to sea level rise or storm surge is low compared to the likelihood of vaults flooding due to extreme rainfall events. If a vault is flooded, the electrical equipment in the vault can be partially or fully submerged, which increases the likelihood of equipment failure. To decrease the risk of equipment failure, Maritime Electric will perform vault inspections directly following extreme rainfall events that exceed 106 mm of rain in 24 hours.[30] If equipment is submerged, Maritime Electric will pump water out of the vault immediately to minimize the amount of time that the equipment is submerged.

Maritime Electric's existing Underground Facility Inspection Report includes an area for inspectors to record whether water is present in a vault but does not require inspectors to record the depth of the water level. Maritime Electric will add water level measurements to the report to help track water levels and evaluate trends over time.


*Figure 12: Year 2100 Flood Hazard Map with Maritime Electric Downtown Charlottetown Vaults*

[30] 106 mm of rainfall in 24 hours represents a historical 1-in-25-year rainfall event.

# Operations

## Strategy 8 Adapt vegetation management practices to increasing tree growth rates

Each year, Maritime Electric's system reliability is impacted by trees contacting power lines. Tree contacts most commonly occur during high wind or ice storm events, which result in customer outages. Additionally, the Risk Assessment showed that climate change (i.e., hotter and more humid weather, increased precipitation and longer growing season for trees) will improve growing conditions and increase growth rates for vegetation on PEI.

Hurricane Fiona resulted in an estimated 40,000 fallen trees and large branches that impacted the transmission and distribution system. The majority of these large trees were located outside of the public right-of-way and resulted in significant damage to electrical infrastructure, including damaged conductors, distribution poles and transformers. Since Hurricane Fiona, Maritime Electric has been investigating new methods to further improve vegetation management.

A Vegetation Management Plan Report, recently submitted to IRAC, outlined Maritime Electric's hybrid approach to vegetation management, combining both an increase in risk-based vegetation management and targeted cycle-based vegetation management. Risk-based vegetation management involves identifying high-risk areas for vegetation management. Cycle-based vegetation management involves targeting specific circuits on a cyclical schedule. Increases in vegetation management budgets and the implementation of new programs and technologies will help Maritime Electric perform more targeted risk-based vegetation management, while gradually increasing the level of cycle-based vegetation management.

### Action 8.1 Implement a new right-of-way widening program (planned)

In its 2024 Capital Budget Application to IRAC, Maritime Electric requested approval for two new recurring capital programs for transmission and distribution corridor widening. Most of Maritime Electric's lines are constructed on the edge of provincial rights-of-way, as shown in Figure 13. The objective of the corridor widening programs is to secure wider corridors that will allow the removal of vegetation that is currently outside or adjacent to the provincial rights-of-way. Removal of vegetation adjacent to lines provides multiple benefits, including reduced risk of tree contacts and wildfire from new growth and reductions in future vegetation management requirements. Maritime Electric will continue to collaborate with the Government of PEI to improve the effectiveness of the vegetation management program through legislative authority or some other means to manage vegetation on private property directly adjacent to the public right-of-way to maintain the safety and reliability of the transmission and distribution system.

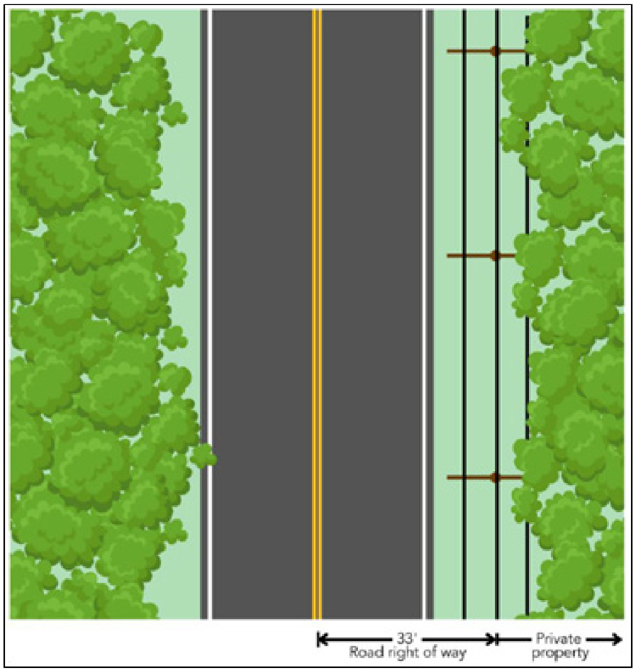


*Figure 13: Power Lines in Provincial Rights-of-Way*

### Action 8.2 Increase the vegetation management budget (in progress)

Over the past five years, Maritime Electric has progressively increased its investments in vegetation management and the 2024 Capital Budget Application requested approval for two new recurring capital programs for transmission and distribution corridor widening (see Action 8.1). If approved, the capital programs will increase the total investment in vegetation management to approximately $4.4 million in 2024 and $5.2 million in 2025. By 2025, Maritime Electric projects its annual vegetation management budget to be more than double of its 2021 budget. Further budget increases will be required because of increasing tree growth rates due to increasing temperatures, longer growing seasons and increasing precipitation.

### Action 8.3 Evaluate the use of satellite technology for vegetation management planning (in progress)

Maritime Electric is currently exploring the use of satellite-based software technologies to enhance the vegetation management planning process. Satellite-based technologies use high-resolution satellite imagery and predictive models to analyze current vegetation condition, growth rates and risk. Maritime Electric can use the software technology to prioritize its vegetation management efforts and monitor progress over time. The software also typically offers planning, cost estimating, execution and audit modules.

Maritime Electric is currently conducting a pilot project with a satellite-based vegetation management technology, which will analyze approximately 275 kms of distribution line across three circuits and 27 kms of transmission line. The three distribution circuits were selected based on their reliability performance, differing types of vegetation condition, and combination of suburban and rural environments. Figure 14 shows an example of the initial assessment for distribution lines prior to field verification.

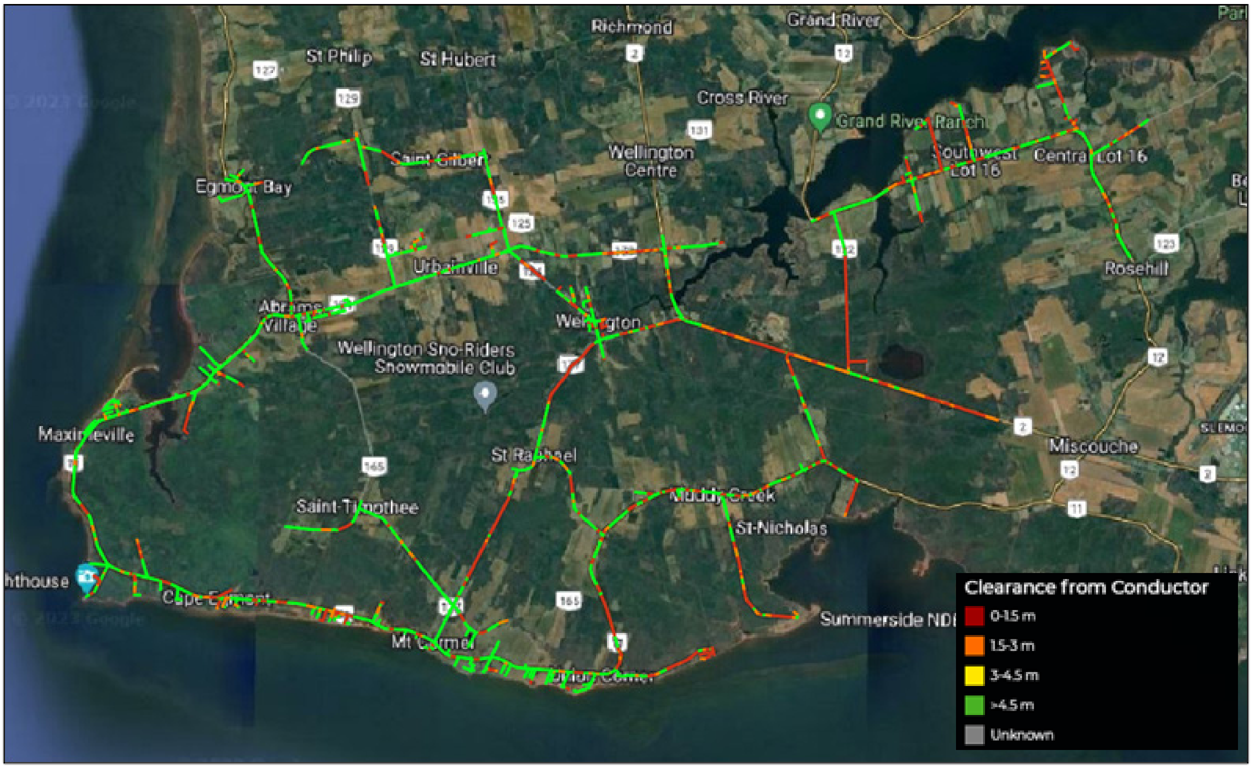


*Figure 14: Sample Satellite-Based Vegetation Condition Assessment of Distribution Lines*

### Action 8.4 Develop a vegetation education and planting information campaign (in progress)

Maritime Electric is actively working with municipalities and private landowners to promote planting trees away from power lines as part of a vegetation education and planting information campaign. Examples of marketing materials distributed to municipalities and customers is provided in Appendix B: Vegetation Education and Planting Promotional Materials. In 2023, Maritime Electric also launched a Right Tree Right Place campaign to promote and educate municipalities and landowners about planting low-growth tree species near power lines and safe distances to plant trees away from power lines and updated its Tree Planting Guide, which is provided in Appendix C: Tree Planting Guide.

## Strategy 9 Continue to monitor coastal erosion near subsea cable termination sites

Sea level rise and storm surge has the potential to impact subsea cable land termination areas if significant costal erosion occurs. Although not identified as an immediate risk in the Risk Assessment, coastal erosion was identified as a significant risk for PEI by the Government of PEI.[31] In 2017, Maritime Electric constructed riser stations in Borden-Carleton and Cape Tormentine to terminate two new 138 kV subsea cables between PEI and New Brunswick, which included the installation of stonewalls for shoreline protection to prevent erosion near the subsea cables.[32] Annually, Maritime Electric inspects the stonewalls to ensure that they remain in good condition. Maritime Electric also maintains the original two subsea cables that were installed in 1977; however, the riser stations and associated subsea cable equipment for these cables are located further from the shore. All stations and associated equipment are inspected routinely, and the subsea cables are inspected biennially by divers. The four subsea cables and their termination sites are critical to maintain Maritime Electric's supply of electricity from NB Power. Maritime Electric will continue to monitor coastal erosion near the four cable termination sites on PEI and in New Brunswick.

### Action 9.1 Develop a standardized inspection report to document the condition of the shoreline near subsea cable terminations on PEI and in New Brunswick (complete)

Coastal erosion caused by sea level rise and storm surges could impact the four subsea cable termination areas. To monitor coastal erosion, inspections should occur after each storm surge event. In 2023, Maritime Electric developed a new form to document and inspect results for the four subsea cable termination locations on PEI and in New Brunswick, which is provided in Appendix D: Subsea Cable Shoreline Inspection Form. The inspection form includes the following:

- Inspection of the shoreline for sink holes or heaving;
- Inspection of armor stone shoreline protection wall (if applicable) for deterioration;
- Inspection of road crossings for sink holes or heaving;
- Inspection of right of way for sink holes, heaving or public interference; and
- Photograph documentation of site conditions.

The inspections will be completed following major storm surge events.

[31] ICF International Inc. 2021. Prince Edward Island (PEI) Climate Change Risk Assessment. Government of Prince Edward Island.

[32] A riser station is an electrical station that transfers electricity from underground to overhead or vice versa.

## Resiliency

### Strategy 10 Continue to implement redundancy within the electrical grid

Adding redundancy to the electrical grid provides flexibility to supply electricity to customers from alternate routes in the event of an outage. Examples of electrical grid redundancy include adding subsea cables and transmission lines, creating transmission loops, adding capabilities to feed circuits from alternate substations and adding redundancy to equipment within substations.

In 2017, with the Government of PEI, Maritime Electric acted as the construction agent and installed two new subsea cables that connect PEI to New Brunswick, which increased the total number of subsea cables to four. The ability to supply electricity via four subsea cables provides PEI with redundancy in the event that one of the cables were to fail. In 2017, Maritime Electric also completed a new 138 kV transmission line Y-104 and expanded a substation in Church Road to create a transmission loop in Eastern PEI. In the event of a fault on one of the transmission lines, the transmission loop allows customers to be serviced from the alternate transmission line.

Maritime Electric is continuously expanding existing and constructing new substations to service increasing customer loads and, in some cases, this provides additional redundancy to the distribution system. For example, in 2020, Maritime Electric constructed a new substation in Clyde River to service customers in Cornwall and surrounding areas, who were previously serviced from the West Royalty substation. At the time, electrical switching devices (e.g., reclosers) were installed to allow customers in the area to be serviced from either the new Clyde River substation or the existing West Royalty substation, providing backup options in the event of an outage. Adding new substations also decreases the length of substation feeder circuits, which further improves reliability by reducing the number of customers affected by an outage on a particular circuit.

When Maritime Electric expands existing substations or constructs new ones, it includes redundancy in the substation design. For example, Maritime Electric includes spare transformer bays in new substations to accommodate a mobile power transformer (i.e., a power transformer on a movable trailer). The mobile power transformer can be quickly connected to the substation if a failure occurs to any of the permanent power transformers. The practice of including spare transformer bays is a cost-effective way to add redundancy to critical substation power transformers.

#### Action 10.1 Complete a transmission loop in Western PEI to increase redundancy (in progress)

In 2023, Maritime Electric received regulatory approval to construct a switching station in Western PEI, which will create a transmission loop in the region. The transmission loop will improve reliability in Western PEI as it will provide an alternate route for Maritime Electric to serve customers in the event of an outage to one of the transmission lines. The project is expected to be completed by 2025.

### Action 10.2 Add an additional autotransformer to the Lorne Valley Switching Station and convert T-4 to 138 kV (planned)

Eastern PEI is currently supplied via two transmission lines: (1) a 69 kV transmission line (T-2) originating from the substation at the Charlottetown Generating Station; and (2) a 138 kV transmission line (Y-104 and Y-102) originating from the West Royalty substation. These lines create a 155 km transmission loop, as shown in Figure 15, which supplies power to approximately 30 per cent of Maritime Electric's customers. Transmission line T-4 is not currently connected to the Y-104 transmission feed, as the lines are energized at different voltages. Adding an additional autotransformer to the Lorne Valley switching station and converting T-4 to 138 kV will offload existing autotransformers in the West Royalty substation and provide further redundancy to the 138 kV transmission system for Eastern PEI. The installation of an additional autotransformer in Lorne Valley and the replacement of T-4 is currently planned to start in 2025, subject to regulatory approval.

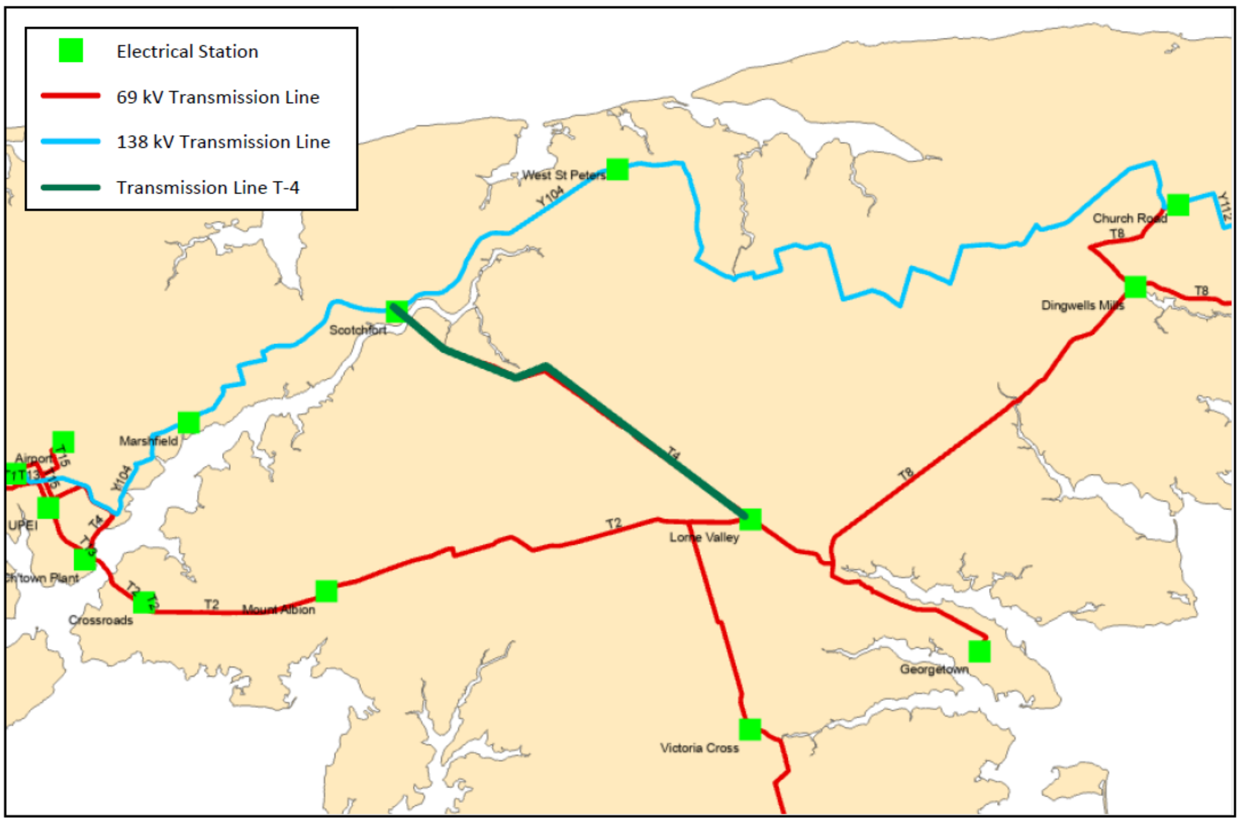


*Figure 15: Eastern PEI Transmission Loop*

### Action 10.3 Extend three-phase distribution lines to provide redundancy (ongoing)

Redundancy on the distribution system can lead to increased reliability during distribution system outages. Maritime Electric is gradually extending strategic three-phase circuits to connect them to other three-phase circuits from neighbouring substations, which serves new customers along the route and allows backup from neighbouring substations. For example, in 2023, Maritime Electric completed a 2.5 km three-phase line conversion on the Robertson Road in Mount Albion, which bridged a 1.1 km gap between two three-phase lines. The new line allows Maritime Electric to transfer load from the Crossroads substation to the Mount Albion substation, which will improve reliability by providing a backup option for approximately 1,800 customers on the Bunbury feeder (from the Crossroads substation). Maritime Electric will prioritize the extension of similar three-phase lines to provide redundancy from different substations and strengthen reliability.

### Action 10.4 Implement more widespread use of Distribution Automation Systems (planned)

A Distribution Automation System ("DAS"), as defined by the Institute of Electrical and Electronic Engineers, is a system that enables an electric utility to monitor, coordinate, and operate distribution components in real-time from remote locations.[33] It is an integrated solution of field apparatus, devices, communications and software applications designed to optimize power grid efficiency, reliability, and resilience.

The benefits of DAS implementation include:

- Improved reliability by reducing outage duration using auto restoration schemes;
- Improved voltage control by means of automatic Volt-Amps Reactive (VAR) control;
- Accurate and useful planning and operational data information;
- Improved fault detection and diagnostic analysis;
- Improved management of system and component loading; and
- Improved utilization of system capacity.

A reliable and cybersecure communication system is critical to a DAS. Maritime Electric is actively working to implement a robust communication system to support DAS by upgrading its communication infrastructure between its Energy Control Centre and substations through the installation of fibre optic lines. The preferred routes for the fibre optic lines are along main distribution feeder lines to facilitate the integration of Supervisory Control and Data Acquisition (SCADA) controlled field devices, including reclosers, voltage regulator controllers and capacitor controllers.[34]

Maritime Electric will develop a DAS plan and intends to complete a DAS pilot project for a selected area. Maritime Electric is investigating available funding opportunities for the pilot project.

## Strategy 11 Adjust load considerations and the timing of planned infrastructure maintenance to reflect projected changes in electricity demand during summer periods

The most significant factor to the timing of planned maintenance and load benchmarks is ambient temperature. For example, scheduled system maintenance is typically avoided during the winter months when electricity load is highest due to home heating requirements. Similarly, peak load analyses and forecasts are based on the coldest day of the year. As the climate on PEI warms and customers utilize

[33] Gruenemeyer, Donald. 1991. "Distribution Automation: How should it be evaluated?" Rural Electric Power Conference. Dearborn, MI, USA: IEEE.

[34] A Supervisory Control and Data Acquisition system is a system of inputs and controls that allows users to monitor and process real-time data.

more air conditioning, summer peak load will increase. The annual peak load is expected to continue to occur during the winter months, but an increase in summer load could impact summer maintenance schedules. Maritime Electric continuously updates its planned maintenance scheduling based on previous and expected peak loads.

#### Action 11.1 Continue to use updated extreme climate benchmarks for maintenance and demand planning (ongoing)

Maritime Electric's Corporate Planning department has already incorporated climate change projections in its planning processes. The department uses extreme maximum and minimum temperatures to estimate future peak loads. Extreme maximum temperatures, in particular, are used to determine the electrical capacity of power transformers located in substations, since the efficiency and capacity of power transformers decrease as the ambient temperature increases. The department also uses the number of heating degree days and cooling degree days to estimate future loads.

### Strategy 12 Collaborate with NB Power on increasing transmission capacity and redundancy

Maritime Electric purchases a significant amount of its energy from NB Power through four subsea cables. In 2022, approximately 73 per cent of electricity delivered to customers came from NB Power imports, which is purchased from NB Power through energy purchase agreements.

#### Action 12.1 Increase the transmission capacity for electricity imports from NB Power (ongoing)

In October 2023, New Brunswick and Nova Scotia announced their intentions to abandon the Atlantic Loop project, aimed at expanding the transmission capacity in Atlantic Canada, due to the project's high cost. Maritime Electric is discussing options with NB Power to increase the transmission capacity for electricity imports to PEI, despite the Atlantic loop project being abandoned. Other options exist to increase the transmission capacity that would have similar benefits as the Atlantic Loop project, which the Atlantic Provinces are evaluating.

#### Action 12.2 Review transmission automation options for the New Brunswick corridor transmission lines (planned)

Currently, if an outage occurs on any of the NB Power transmission lines that deliver electricity to PEI, required protection and control schemes can extend outage durations. The protection and control schemes are required to protect Maritime Electric and NB Power's electrical infrastructure from potential damage. Maritime Electric plans to evaluate automation options for the protection and controls schemes for the New Brunswick corridor transmission lines to determine whether the duration of outages can be reduced safely.

## Strategy 13 Increase backup dispatchable power generation on PEI

Maritime Electric currently owns and operates three combustion turbines used for backup power generation, with a combined capacity of 90 MW. In February 2023, PEI experienced a record peak load of 393.6 MW during a polar vortex weather event. The peak load was 22 per cent higher than the previous record peak (January 2022). As Maritime Electric's peak load continues to increase and the Maritime provinces experience capacity shortages due to electrification and the federally mandated closure of all coal-fired generation by 2030, more generating capacity is required to avoid rotating blackouts for customers. Additional generating capacity can also provide emergency backup power in case of outages to the New Brunswick transmission system or subsea cables that connect PEI to New Brunswick, which recently occurred in February 2024.

### Action 13.1 Implement recommendations from the Capacity Resource Study (planned)

In 2021, Maritime Electric completed a Capacity Resource Study ("Capacity Study") and Extreme Weather Event Capacity Impact Addendum Report ("Addendum Report") to evaluate PEI's capacity requirements, which concluded that Maritime Electric needs more dispatchable generation to support load growth and for security of supply.[35,36] The Capacity Study and Addendum Report recommended installing dispatchable generation. Maritime Electric is currently in the process of preparing an application to IRAC to install additional on-Island dispatchable generation, which is expected to be filed in 2024.

## Strategy 14 Continue to maintain the backup radio system to allow continued communication in the case of disruptions to the fibre system

Maritime Electric owns and maintains radio and fibre optic communication networks between substations and the Energy Control Centre. Energy Control Centre operators use the communication networks to monitor energy flows through the transmission system and to operate substation devices. In recent years, Maritime Electric modernized its communication network by expanding its network of fibre optic lines; however, Maritime Electric continues to maintain its radio network as a backup. The backup radio network was valuable during Hurricane Fiona in 2022, as the storm impacted Maritime Electric's fibre optic network.

### Action 14.1 Continue to maintain Maritime Electric's backup radio network for communication until redundancy is established in the fibre optic network (ongoing)

Maritime Electric will continue to maintain its backup radio network for communication until redundancy is established for its fibre optic network. If Maritime Electric's application to install Advanced Metering Infrastructure is successful, Maritime Electric will evaluate the potential of using the Advanced Metering Infrastructure communication network as an alternative to its existing radio network as a backup.

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[35] Sargent & Lundy. 2022. "Capacity Resource Study - Evaluation of Various Technology Options for Maritime Electric Company." Chicago, IL.

[36] Sargent & Lundy. 2023. "Extreme Weather Event Capacity Impact - Addendum to December 2022 Maritime Electric Capacity Resource Study." Chicago, IL.

## Employee Health and Safety

### Strategy 15 Create procedures for working in extreme weather events

In the past, Maritime Electric's practice was to allow employees to use their judgment while working during an extreme weather event. Additionally, if a lightning storm is approaching, Maritime Electric's Energy Control Centre operators alert field crews, who halt work and take shelter immediately. Due to climate change and the increasing frequency and intensity of extreme weather events, including higher temperatures during summer months, a formal procedure should be created to clarify actions required to protect the health and safety of employees during extreme weather events.

#### Action 15.1 Develop an employee safety procedure for working in extreme weather (complete)

In 2023, Maritime Electric created a new procedure that outlines actions required during extreme weather events. The procedure outlines potential illnesses and symptoms associated with exposure to extreme heat or extreme cold. The procedure also outlines guidelines for working in extreme weather events such as high wind and heavy precipitation. The procedure is provided in Appendix E: Guidelines for Working in Extreme Weather Procedure.

### Strategy 16 Provide appropriate weather-related personal protection equipment to reduce exposure risks and continue to communicate weather-related health and safety risks

The Risk Assessment identified several climate-related risks toward human resources working outdoors. Below is a list of high risks identified:

- Extreme cold temperatures pose a risk of hypothermia and frostbite;
- Extreme heat poses a risk of heat stroke and dehydration;
- Ice storms and freezing rain create a risk of slips and vehicle collisions;
- Lightning poses a risk towards personnel, especially those working on the electrical system; and
- Hurricanes and extratropical storms pose a risk towards personnel who are working on the electrical system or driving.

Maintaining a strong safety culture and raising awareness of climate-related health and safety risks will become increasingly more important as a result of climate change.

#### Action 16.1 Provide Maritime Electric employees with appropriate weather-related personal protection equipment (ongoing)

Maritime Electric provides personnel with appropriate weather-related personal protective equipment ("PPE"), including insulated jackets, insulated pants, rain gear, work boots, ice cleats, hard hats and shaded safety glasses. Maritime Electric is also committed to supplying personnel with sunscreen and water at all times of year to protect employees from the sun and to ensure they remain hydrated. Procedures are in place to ensure employees receive the appropriate PPE to protect them from weather conditions. Maritime

Electric maintains a Joint Occupational Health and Safety Committee, comprised of employees from various departments to address safety gaps, including weather-related PPE.

### Action 16.2 Continue to discuss weather-related health and safety risks (ongoing)

Maritime Electric is grounded in decades of high safety standards. Safety meetings are held monthly with various departments to review health and safety in the workplace, including weather-related safety. Weather-related safety discussions include, but are not limited to, slip hazards from ice, road conditions while driving and the importance of hydration while working outdoors in high temperatures. Maritime Electric will continue to discuss weather-related safety and will review the new Guidelines for Working in Extreme Weather Procedure (see Action 15.1) during safety meetings.

## Strategy 17 Add heat pumps in substation buildings that are frequently occupied by Maritime Electric personnel

All of Maritime Electric's newly constructed substation control buildings include heat pumps for heating and cooling. Maritime Electric is working towards installing heat pumps in all of its existing substation buildings, which predominately contain electric baseboard heating systems. In 2022, Maritime Electric installed heat pumps in its control buildings at the Borden Generating Station, which can be occupied for extended periods of time during the operation of combustion turbines. The control buildings were previously either cold or hot during the winter or summer periods, respectively.

### Action 17.1 Ensure that heat pumps are installed in substation control buildings (planned)

Maritime Electric will continue to install heat pumps in all new substation control buildings and will seek approval to add the installation of heat pumps in existing substation control buildings through its substation modernization program.

# IMPLEMENTATION AND GOVERNANCE

Maritime Electric's Operations and Engineering departments will be responsible for implementing the strategies outlined in the Adaptation Strategy. The Sustainability Department will be responsible for monitoring and reporting on the implementation of the strategies and action items.

The Sustainability Department will continue to monitor emerging climate information and industry best practices for climate change adaptation. Climate data and adaptation strategies will be updated as new information becomes available. Maritime Electric intends to update its Risk Assessment at a minimum every five years to include current climate change projections and review its climate change risks based on adaptation efforts. Maritime Electric also plans to monitor progress towards completing the climate change adaptation strategies and action items.

Updates of Maritime Electric's sustainability and climate change adaptation work is provided to Maritime Electric's Human Resources and Corporate Governance Committee of the Board of Directors. Fortis Inc. also provides oversight on climate change adaptation and the Fortis Operating Group, comprised of all Fortis companies, shares climate change adaptation and resilience resources. Local climate expertise on PEI, strong governance from Maritime Electric's Board and oversight from Fortis Inc. allows for Maritime Electric to be well positioned for implementing effective climate change adaptation strategies.

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# APPENDIX A:
# STANTEC CLIMATE DATA

**Table 1 Summary of Climate Data for Wind, Temperature, and Precipitation Extreme Events**

| Climate Parameters | Average [A] | | 1 in 25-year event | | 1 in 50-year event | | 1 in 100-year event | | Projection Confidence Level |
|---|---|---|---|---|---|---|---|---|---|
| | Baseline | 2070s | Baseline | 2070s [B] | Baseline | 2070s [B] | Baseline | 2070s [B] | |
| Sustained wind speed (km/h) | **82** | **84** *(81 – 86)* | **121** | **124** *(120 – 126)* | **127** | **130** *(125 – 132)* | **132** | **136** *(130 – 137)* | Low |
| Wind gusts (km/h) | **111** | **113** *(109 – 115)* | **164** | **168** *(161 – 170)* | **172** | **176** *(169 – 179)* | **179** | **183** *(176 – 186)* | Low |
| Radial ice accretion (mm) [C] | **10** | **5** *(3.8 – 6.6)* [D] | **31** | **16** *(10 – 23)* [D] | **35** | **18** *(11 – 26)* [D] | **39** | **20** *(13 – 29)* [D] | Low |
| High daily average temperature (°C) | **24.7** | **29.1** *(28.5 – 30.3)* | **26.0** | **30.4** *(29.8 – 31.6)* | **26.2** | **30.6** *(30.0 – 31.9)* | **26.3** | **30.7** *(30.1 – 31.9)* | High |
| Extreme maximum temperature (°C) | **30.3** | **34.9** *(33.7 – 35.8)* | **32.3** | **37.0** *(36.4 – 37.5)* | **32.7** | **37.3** *(36.8 – 37.9)* | **33.0** | **37.6** *(37.0 – 38.2)* | High |
| Extreme minimum temperature (°C) | **-23** | **-14.2** *(-16.8 to -11.6)* | **-30.3** | **-21.5** *(-22.9 to -20.0)* | **-32.0** | **-23.2** *(-24.6 to -21.7)* | **-33.6** | **-24.8** *(-26.2 to -23.3)* | High |
| Heat waves (number of days per year) [E] | **1** | **22** *(18 – 33)* | **4** | **39** *(34 – 53)* | **5** | **44** *(38 – 58)* | **6** | **48** *(42 – 63)* | High |
| Extreme rainfall – 1-hour duration (mm) | **18.7** [F] | **25.4** [F] *(24.4 – 26.1)* | **33.3** | **44.8** *(43.1 – 48.6)* | **36.9** | **49.7** *(47.7 – 53.9)* | **40.5** | **54.5** *(52.4 – 59.2)* | Moderate |
| Extreme rainfall – 24-hour duration (mm) | **60.5** [F] | **82.1** [F] *(78.9 – 84.3)* | **106** | **142** *(137 – 155)* | **117** | **158** *(151 – 171)* | **128** | **173** *(166 – 187)* | Moderate |

Notes:

[A] The average of the annual extreme values for each climate parameter
[B] Projected values include the **median** value, along with the *($10^{th}$ – $90^{th}$)* percentile.
[C] Baseline values of ice accretion were estimated using the Chainé model following CSA 22.3 No. 60826:19
[D] Values in parentheses are the $25^{th}$ and $75^{th}$ percentiles.
[E] Heat waves are defined as 2 consecutive days with Tmax >= 28 °C and Tmin >= 18 °C. For example, if a given year had only 1 day meeting that criteria, the number of heat waves would be 0, and so the number of days per year with heat wave conditions would also be 0. Another year where one heat wave occurred that lasted 3 days would have a total of 3 days in that year with heat wave conditions.
[F] Extreme rainfall average is represented as the 2-year return period event from the available Intensity-Duration-Frequency data for Charlottetown

**Table 2 Summary of Climate Data for Sea Level Rise and Storm Surge near Charlottetown**

| Climate Parameter | | Time Period | | Projection Confidence Level |
|---|---|---|---|---|
| | | Baseline | End of Century | |
| Sea Level Rise (m) | | - | 0.65 (0.34 – 0.96) [A] | Moderate |
| Storm Surge (m) | 1-year | 1.3 | 2.1 | Moderate |
| | 10-year | 1.8 | 2.6 | |
| | 100-year | 2.2 | 3.1 | |

Notes

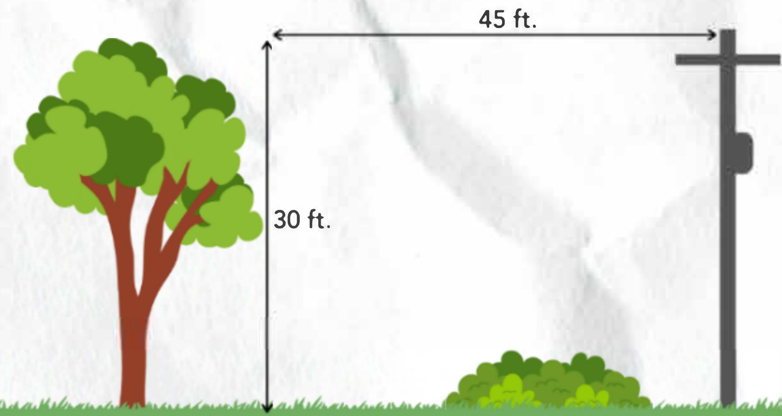
[A] Sea Level Rise shown as the median along with the $5^{th}$ and $95^{th}$ percentile values

# APPENDIX B: VEGETATION EDUCATION AND PLANTING PROMOTIONAL MATERIALS

### TREE PLANTING

# IMPORTANT NOTICE

## PLANT THE RIGHT TREE IN THE RIGHT PLACE.




### IMPORTANT TREE PLANTING SAFETY MESSAGE

If you are planting new trees, do not plant near or under power lines. Before choosing a place to plant, always check how tall the tree will be when it grows to maturity. A 30 ft. tree at maturity should be planted at least 45 ft. away from power lines to help prevent future safety hazards or risk of power outages. Please do not plant trees near power lines.

To learn more, and to read our tree planting guide, scan the QR code using the camera on your smart device or visit maritimeelectric.com.

# PLANT SMART: KEEP THE LINES IN MIND.

**Islanders, we need your help!**
Trees planted near and under power lines interfere with the reliability of your power and may cause power outages.

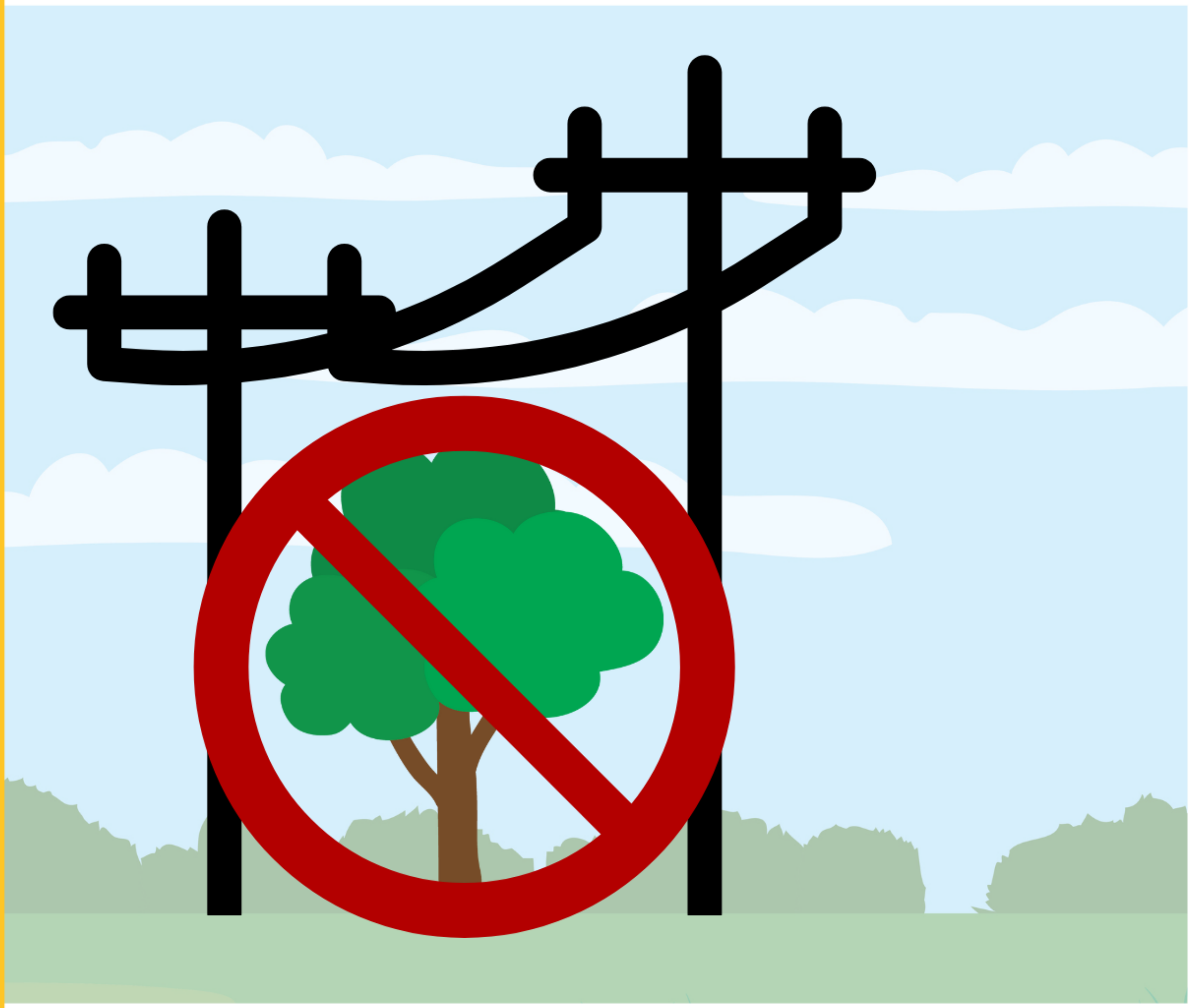
**Please, do not plant trees near power lines.**

Scan with your mobile camera to read our tree planting guide!

1-800-670-1012 maritimeelectric.com
@MECLPEI Maritime Electric

MARITIME ELECTRIC
A FORTIS COMPANY

# APPENDIX C:
# TREE PLANTING GUIDE



# TREE PLANTING GUIDE

Plant Smart: *Keep the Lines in Mind*

MARITIME ELECTRIC
A FORTIS COMPANY

## Trees and Power Lines

We are committed to providing safe, reliable and affordable electricity for our customers. We also know the importance of planting trees for our environment and communities and plant many trees through corporate programs each year. However, planting trees near or under power lines will result in power outages and create a future public safety hazard. Trees and wind are the number one cause of power outages in Prince Edward Island. Trees planted near and under power lines interfere with the electrical equipment and the reliability of the power being delivered to your home, neighbours and wider community. This is especially true during adverse weather events including high winds and ice storms.

We regularly trim trees away from power lines to ensure the reliability of our electrical system and reduce the risk of public safety hazards, but we need your help. We encourage you to read through this guide, which will assist you in making informed decisions about planting the right tree in the right place. Not only will planting your tree in the right place ensure the best chances of your tree establishing and growing to maturity, but it will also ensure the reliability of the electrical system in your community.

## Plan Before You Plant

If you are planting a new tree, consider how large it will grow and what it will look like in 10 or even 20 years. Before choosing a place to plant your tree, contact your local tree nursery to determine the mature height of the tree. A 30 ft. tree at maturity should be planted at least 45 ft. away from power lines to help ensure it will not interfere with the power lines in the future. The taller the tree, the further away the tree needs to be planted from the power lines to ensure the reliability of the power system. Only low growing species should be planted in proximity to power lines.

## Choosing Trees for your Island Property

Planting native species is highly recommended as they have adapted for thousands of years to survive and thrive in the conditions on Prince Edward Island. Native species also work to protect the soil and waterways and provide a multitude of other benefits to the PEI ecosystem. Visit MacPhail Woods Ecological Forestry Project's website for a list of native tree species.

**White Spruce**

- Mature height: 78 to 98 ft
- Grows best in full sun
- Ideal for hedgerows, in old fields and along the coastline
- **Plant very far away from power lines**

**Sugar Maple**

- Mature height: Up to 115 ft
- Grows best in rich, well-drained soil and in dry areas with partial shade
- Does not tolerate windy areas
- **Plant very far away from power lines**

**Red Maple**

- Mature height: Up to 82 ft
- Grows best in rich and moist soil, often found near streams and swamps
- Tolerates some shade
- **Plant very far away from power lines**

**Red Oak**

- Mature height: Up to 65 to 98 ft
- Grows best in well-drained soil
- Does not tolerate windy areas or very wet soil
- **Plant very far away from power lines**

## Planting Instructions

1. Identify the trunk flare, which is where the trunk expands at the base of the tree. This point should be partially visible after the tree has been planted.

2. Dig a shallow, broad planting hole that is twice as wide and just as deep as the pot. If the tree is planted too deep new roots will have difficulty developing because of a lack of oxygen.

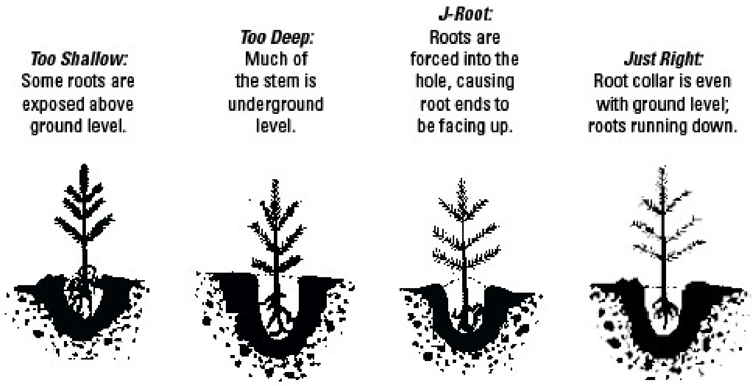
3. Remove broken or damaged branches. Remove the plastic container and spread the roots out. Inspect the root balls for circling roots. If there are a lot of them circling after being confined in the pot straighten them out or cut them with a knife.

4. If the surrounding soil is dry add water to the hole. Add compost and mix it with the loose soil in the hole.

5. Straighten the tree in the hole. Before backfilling, have someone view the tree from several directions to confirm it is straight.

6. Fill the hole gently but firmly. Pack soil around the base and sides of the root ball to stabilize it.

7. Create a barrier with soil around the tree to hold water.




## Mulching the Base

1. Apply a 2 to 4 inch (5 to 10 cm) layer of mulch (less if poorly drained). Coarse mulches can be applied slightly deeper without harm. Mulch should not come in contact with the tree trunk.

2. Place mulch out to the edge of a tree's crown or beyond. Trees like their entire root systems to be mulched.

## Watering

Water your newly planted tree twice per week for the first two months, or three times per week in the summer months.

## Weeding

Keep the area around your newly planted tree weed free. Hand pull weeds to avoid damaging the trunk with a lawnmower or weed trimmer.

## Fertilizing

Fertilize your new trees annually. Fertilizers with a high nitrogen content are recommended for trees under three years old. Follow the instructions on the package to ensure proper amounts and application.

## Plant for Energy Efficiency

Properly selected and planted trees around a home can also improve energy efficiency. When trees are planted in the right places they can provide you with energy savings by shielding cold winds during the winter months. Here are a few tips:

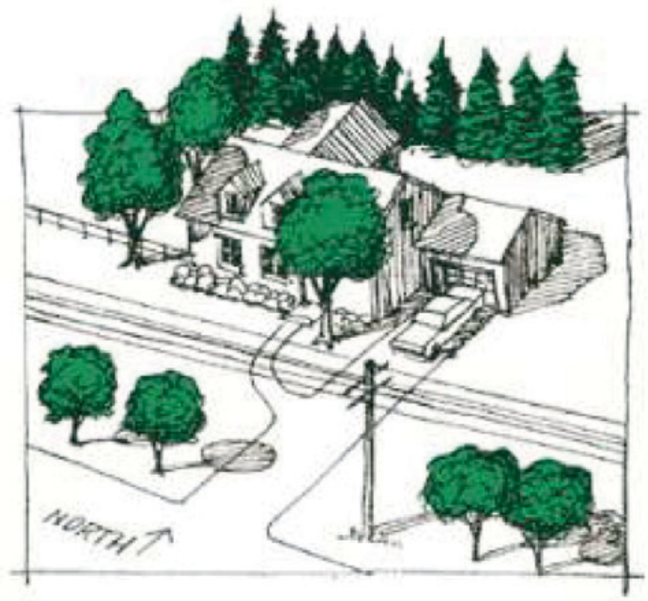
- Plant a windbreak of evergreens to the north and west of your house (away from power lines) to provide shelter from the cold winter winds and to help save energy in winter.
- Plant deciduous trees on west and southwest sides (away from power lines) since these trees lose their leaves in the winter. This will allow sunlight to help with heating and therefore help reduce your energy costs.

### Good Placement

Deciduous trees are planted to the south and west of the house. These trees will let the warm sun shine into the house in the winter. The windbreak of evergreens to the north side of the property will shelter the house in winter.

### Bad Placement

Large trees placed under the power lines have to be trimmed. The large evergreen planted on the south side of the house will prevent the winter sun from warming the house.




## Tree Trimming

We understand the importance of planting trees for our environment and communities. However, our ability to provide safe and reliable electricity to over 87,000 customers is affected by the growth of trees. We trim and remove trees to maintain the proper clearance from power lines to ensure the reliability of our system, as well as the safety of Islanders.

Our tree trimming program is aimed at keeping over 6,600 km of transmission and distribution lines clear of trees and undergrowth. Through our focus on effective vegetation management, which includes periodic inspections of power lines, we identify trees that are growing too close to power lines and thus, cause concern for public safety and reliability.

Vegetation and trees have been cleared from power lines to ensure correct distance and safety requirements are in place.

Although it is not possible to predict or foresee all tree-related problems, our tree trimming program is designed to trim trees before safety or reliability problems occur.

## Professional Care

We employ contractors whose skilled, professional crews trim trees to provide enough clearance between limbs with minimum inconvenience to you, our customers.

We encourage our contractors to use a natural trimming method, which is proven to be the best method for the long-term health of the tree. They do their best to redirect growth away from the power lines, creating sufficient clearance so that the tree will remain safe until we return for the next routine maintenance.

**Never attempt to prune or trim trees near power lines yourself. Contact with a power line can result in serious injury or even death.**

## Stay Safe Around Trees

At Maritime Electric, we believe safety must be integrated in all we do.

When a tree or a large branch falls onto a power line, as sometimes happens during storms, it can bring down the power line. If anyone touches a downed power line that is still energized, the result can be serious injury, even death.

Children do not always know, or remember, what can be dangerous, so it is up to the rest of us to watch out for their safety. Never build a tree house in the trees near power lines and be careful not to allow kids to climb trees growing near power lines. Teach them to tell an adult if they discover downed power lines in the area. Never attempt to touch an object tangled in a power line. Call Maritime Electric at **1-800-670-1012**, for assistance.

## Our Commitment to the Environment

Introduced in 2019, Trees for Life is a Maritime Electric employee tree planting event that focuses on community engagement and sustainability. Each year, Maritime Electric purchases trees from Island nurseries and plants them in September at Island schools or parks. Since the program began, we've planted hundreds of trees across the Island.

To read more about Trees for Life, and our sustainability goals, visit www.maritimeelectric.com/sustainability.

## Let's Work Together

We take our job of providing electricity to your home and community very seriously and we appreciate cooperation in supporting our vegetation management program. By working together, we can ensure the safety of you, your families and our employees.

For further information on tree safety or to report a downed limb or limbs in contact with power lines, visit us online at **maritimeelectric.com** or call us at **1-800-670-1012**.

## The Power of a Moment

If you knew that cutting a tree around an energized power line could cause you or others serious injury or even death, wouldn't you take a moment to look up? NEVER cut or trim trees near power lines and NEVER attempt to remove a tree that has fallen into a power line.

Contractors, be sure your employees know the dangers of working near power lines. It is your responsibility to ensure they follow the Occupational Health and Safety regulations to protect themselves and others. Put safety first, look up before you cut.

**Safety is our priority. Make it yours too!**

Trees and wind are the number one cause of power outages in Prince Edward Island and planting trees near or under power lines may result in power outages.

Trees planted near and under power lines interfere with the electrical equipment and the reliability of the power being delivered to your home, neighbours and wider community.

# APPENDIX D: SUBSEA CABLE SHORELINE INSPECTION FORM

MARITIME ELECTRIC
A FORTIS COMPANY

# Subsea Cable Shoreline Inspection Form

Form #303203A
Date Issued: Mar. 20, 2024


Date: ______________________ Inspected By: ______________________

| **Richmond Cove** | | **OK** | **Deficient** | **Comment** |
|---|---|---|---|---|
| Shoreline beach | Check for sink holes, heaving or signs of oil spills | | | |
| Armour stone wall | Check for deterioration or loose rocks | | | |
| Right-of-way land area | Check for sink holes, heaving or public interference | | | |
| Photos | Take photos of shoreline and right-of way land area | | | |
| Other: | | | | |

| **Murray Corner** | | **OK** | **Deficient** | **Comment** |
|---|---|---|---|---|
| Shoreline beach | Check for sink holes, heaving or signs of oil spills | | | |
| Armour stone wall | Check for deterioration or loose rocks | | | |
| Road crossing | Check for dips, sink holes or heaving | | | |
| Right-of-way land area | Check for sink holes, heaving or public interference | | | |
| Photos | Take photos of shoreline and right-of way land area | | | |
| Other: | | | | |

| **Borden-Carleton** | | **OK** | **Deficient** | **Comment** |
|---|---|---|---|---|
| Shoreline beach | Check for sink holes or heaving | | | |
| Armour stone wall | Check for deterioration or loose rocks | | | |
| Right-of-way land area | Check for sink holes, heaving or public interference | | | |
| Photos | Take photos of shoreline and right-of way land area | | | |
| Other: | | | | |

| **Cape Tormentine** | | **OK** | **Deficient** | **Comment** |
|---|---|---|---|---|
| Shoreline beach | Check for sink holes or heaving | | | |
| Armour stone wall | Check for deterioration or loose rocks | | | |
| Road crossing | Check for dips, sink holes or heaving | | | |
| Right-of-way land area | Check for sink holes, heaving or public interference | | | |
| Photos | Take photos of shoreline and right-of way land area | | | |
| Other: | | | | |

| **Comments** |
| --- |
| |

Send inspection form and photos to: Manager, Corporate & Capital Planning

# APPENDIX E:
# GUIDELINES FOR WORKING IN EXTREME WEATHER PROCEDURE

| | | |
|---|---|---|
| MARITIME ELECTRIC A FORTIS COMPANY | **Document** | 850233 |
| | **Version #** | 01 |
| | **Effective Date** | May 6, 2024 |
| | **Owner** | Manager, Customer Service & Operations |
| | **Approver/Title** | Enrique Riveroll |

## 1.0 PURPOSE

1.1 The purpose of this procedure is to outline the extreme weather events that Prince Edward Island currently faces or could potentially face as climate changes. For each weather event, there is a description, potential illnesses and symptoms, and recommended safety guidelines. The information outlined in this procedure is considered to be used as a guideline, it should never supersede good judgment if a situation feels unsafe.

## 2.0 POLICY

2.1 This procedure applies to all employees and applicable contractors whose role requires them to work outside.

## 3.0 DEFINITIONS

3.1 ***Extreme Cold*** is temperature with wind chill at or below -35°C in Atlantic Canada or between -30°C and -55°C in other regions of Canada.

3.2 ***Extreme Heat*** is temperatures at or above 28°C, with nighttime temperatures of 18°C or above on Prince Edward Island or between 28°C and 35°C in other regions of Canada with nighttime temperatures between 13°C to 21°C.

3.3 ***High Winds*** are when the wind is sustained at 70 km/h or higher, and/or when there are gusts of 90 km/h or higher.

3.4 ***Heavy Rain*** is when 25 mm or more of rain is expected to fall within one hour within Atlantic Canada and northern provinces and territories or when 50 mm or more of rain is expected to fall within one hour in other regions of Canada.

3.5 ***Heavy Snowfall*** is when 15 cm or more of snow is expected to fall within 12 hours or less in Atlantic Canada, Quebec, Ontario, and regions of British Columbia or between 10 cm or 20 cm within other areas of Canada.

## 4.0 PROCEDURES

***Extreme Cold***

4.1 Environment and Climate Change Canada issues extreme cold warnings when the wind chill is expected to reach -35°C within Atlantic Canada or between -30°C and -55°C in other regions of Canada. There are no legislated maximum/minimum limits for working in the cold, however the following guidelines should be used when the wind chill temperature is at or below -12°C:

- Adjust pace of work to avoid heavy sweating resulting in wet or damp clothing;
- Dress in layers so that you can adjust to changing weather; try not to overdress;
- Allow additional time for new employees to adjust to the conditions;

- Account for additional weight and bulk of clothing when estimating performance and lifting heavy weights;
- Minimize sitting or standing for long periods of time;
- Consume warm fluid and light snacks to provide energy, warmth and to avoid fluid loss;
- Work with the wind at your back, if possible; and
- Rotate shifts in a heated vehicle.

4.2 The symptoms of different cold related illnesses are listed below.

Hypothermia:
- Confusion
- Dizziness
- Memory Loss
- Exhaustion
- Slurred speech or mumbling
- Drowsiness
- Shivering
- Weak pulse
- Slow, shallow breathing

Frostbite:
- Gray, white, or yellow skin discoloration
- Numbness
- Waxy feeling skin
- Loss of feeling

4.3 Environment and Climate Change Canada estimates wind chill based on air temperature and wind speed as shown in Table 1.

**Table 1**

**WIND CHILL TEMPERATURE INDEX**
Frostbite Times are for Exposed Facial Skin

Air Temperature (°C)

| Wind Speed (km/h) | 5 | 0 | -5 | -10 | -15 | -20 | -25 | -30 | -35 | -40 | -45 | -50 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | 4 | -2 | -7 | -13 | -19 | -24 | -30 | -36 | -41 | -47 | -53 | -58 |
| 10 | 3 | -3 | -9 | -15 | -21 | -27 | -33 | -39 | -45 | -51 | -57 | -63 |
| 15 | 2 | -4 | -11 | -17 | -23 | -29 | -35 | -41 | -48 | -54 | -60 | -66 |
| 20 | 1 | -5 | -12 | -18 | -24 | -30 | -37 | -43 | -49 | -56 | -62 | -68 |
| 25 | 1 | -6 | -12 | -19 | -25 | -32 | -38 | -44 | -51 | -57 | -64 | -70 |
| 30 | 0 | -6 | -13 | -20 | -26 | -33 | -39 | -46 | -52 | -59 | -65 | -72 |
| 35 | 0 | -7 | -14 | -20 | -27 | -33 | -40 | -47 | -53 | -60 | -66 | -73 |
| 40 | -1 | -7 | -14 | -21 | -27 | -34 | -41 | -48 | -54 | -61 | -68 | -74 |
| 45 | -1 | -8 | -15 | -21 | -28 | -35 | -42 | -48 | -55 | -62 | -69 | -75 |
| 50 | -1 | -8 | -15 | -22 | -29 | -35 | -42 | -49 | -56 | -63 | -69 | -76 |
| 55 | -2 | -8 | -15 | -22 | -29 | -36 | -43 | -50 | -57 | -63 | -70 | -77 |
| 60 | -2 | -9 | -16 | -23 | -30 | -36 | -43 | -50 | -57 | -64 | -71 | -78 |
| 65 | -2 | -9 | -16 | -23 | -30 | -37 | -44 | -51 | -58 | -65 | -72 | -79 |
| 70 | -2 | -9 | -16 | -23 | -30 | -37 | -44 | -51 | -58 | -65 | -72 | -80 |
| 75 | -3 | -10 | -17 | -24 | -31 | -38 | -45 | -52 | -59 | -66 | -73 | -80 |
| 80 | -3 | -10 | -17 | -24 | -31 | -38 | -45 | -52 | -60 | -67 | -74 | -81 |

**FROSTBITE GUIDE**

Increasing risk of frostbite for most people in 10 to 30 minutes of exposure
High risk for most people in 5 to 10 minutes of exposure
High risk for most people in 2 to 5 minutes of exposure
High risk for most people in 2 minutes of exposure or less

4.4 Additional health concerns and guidelines for various wind chill temperatures provided by Environment and Climate Change Canada are detailed in Table 2.

**TABLE 2**
**Wind Chill Hazards and What to Do**

| Wind Chill | Exposure Risk | Health Concerns | What to Do |
|---|---|---|---|
| 0 to -9 | **Low risk** | ▪ Slight increase in discomfort. | ▪ Dress warmly.<br>▪ Stay dry. |
| -10 to -27 | **Moderate risk** | ▪ Uncomfortable.<br>▪ Risk of hypothermia and frostbite if outside for long periods without adequate protection. | ▪ Dress in layers of warm clothing, with an outer layer that is wind-resistant.<br>▪ Wear a hat, insulated gloves, a scarf and insulated, waterproof footwear.<br>▪ Stay dry and keep active. |
| -28 to -39 | **High Risk**: exposed skin can freeze in 10 to 30 minutes | ▪ High risk of frostnip frostbite: Check face and extremities for numbness or whiteness.<br>▪ High risk of hypothermia if outside for long periods without adequate clothing or shelter from wind and cold. | ▪ Dress in layers of warm clothing, with an outer layer that is wind-resistant<br>▪ Cover exposed skin.<br>▪ Wear a hat, mittens or insulated gloves, a scarf, neck tube or face mask and insulated, waterproof footwear.<br>▪ Stay dry.<br>▪ Keep active. |
| -40 to -47 | **Very high risk**: exposed skin can freeze in 5 to 10 minutes (In sustained winds over 50 km/h, frostbite can occur faster than indicated.) | ▪ Very high risk of frostbite: Check face and extremities for numbness or whiteness.<br>▪ Very high risk of hypothermia if outside for long periods without adequate clothing or shelter from wind and cold. | ▪ Dress in layers of warm clothing, with an outer layer that is wind-resistant.<br>▪ Cover all exposed skin.<br>▪ Wear a hat, mittens or insulated gloves, a scarf, neck tube or face mask and insulated, waterproof footwear.<br>▪ Stay dry.<br>▪ Keep active. |
| -48 to -54 | **Severe risk**: exposed skin can freeze in 2 to 5 minutes (In sustained winds over 50 km/h, frostbite can occur faster than indicated.) | ▪ Severe risk of frostbite: Check face and extremities frequently for numbness or whiteness.<br>▪ Severe risk of hypothermia if outside for long periods without adequate clothing or shelter from wind and cold. | ▪ Be careful. Dress very warmly in layers of clothing, with an outer layer that is wind-resistant.<br>▪ **Cover all exposed skin**.<br>▪ Wear a hat, mittens or insulated gloves, a scarf, neck tube or face mask and insulated, waterproof footwear.<br>▪ **Be ready to cut short or cancel outdoor activities**.<br>▪ Stay dry.<br>▪ Keep active. |
| -55 and colder | **Extreme risk**: exposed skin can freeze in less than 2 minutes | ▪ **DANGER!** Outdoor conditions are **hazardous.** | ▪ **Stay indoors**. |

***Extreme Heat and Humidity***

4.5 Environment and Climate Change Canada issues extreme heat warnings when two or more consecutive days are expected to reach temperatures at or above 28°C, with nighttime temperatures of 18°C on Prince Edward Island or between 28°C and 35°C in other regions of Canada with nighttime temperatures between 13°C to 21°C.

4.6 There are no legislated maximum/minimum limits for working extreme heat, however the following guidelines should be followed:

- Use fans or air conditioning and allow access to cooler areas for breaks;
- Wear light, loose-fitting clothing;
- Take breaks more frequently;
- Drink cold beverages that do not contain caffeine or alcohol, one cup of cool water every 20 minutes is best;
- Rearrange work schedules to do less physically demanding work during peak temperature periods;
- Use tents, screens, or umbrellas to create shade;
- Get acclimated to the hot weather, people not acclimated are more susceptible to heat related illness;
- Wear sunscreen to protect yourself from sunburns; and
- Be cautious when taking medications as some can affect your body's ability to stay hydrated and dissipate heat.

4.7 The symptoms of different heat related illnesses are listed below.

Heat Stroke Warning Symptoms:

- Abdominal cramps
- Muscle cramps
- Nausea
- Vomiting
- Headache
- Dizziness
- Weakness
- Heavy sweat or lack of sweat
- Very high body temperature

Heat Stroke Symptoms:

- Odd or bizarre behavior
- Irritability
- Delusions
- Hallucinations
- Seizures
- Coma

Heat Exhaustion:

- Cool, moist skin with goose bumps while in heat
- Heavy Sweating
- Faintness
- Dizziness
- Fatigue
- Weak, rapid pulse
- Low blood pressure upon standing
- Muscle cramps
- Nausea
- Headache

Mild to Moderate Dehydration:

- Increased thirst
- Dry mouth
- Tire or sleepy
- Decreased urine output
- Urine is low volume and more yellow than normal
- Headache
- Dry skin
- Dizziness
- Few or no tears

Severe Dehydration:

- Severely decreased urine output or no urine output.
- Dark yellow colour urine.
- Dizziness or light-headedness that does not allow the person to stand or walk normally.
- Blood pressure drops when standing up after lying down

Severe Dehydration Continued:

- Rapid heart rate
- Fever
- Poor skin elasticity
- Lethargy, confusion, or coma
- Seizure
- Shock

4.8 Extreme humidity is any humidex reading above 40°C and unnecessary physical activity should be reduced as much as possible. If the humidex reading is in the high to mid-30°Cs, the level of work should be reduced depending on individual age, health, and clothes worn.

4.9 Recommended actions depending on the humidex reading prepared by The Occupational Health Clinics for Ontario Workers Inc. in shown in Table 3.

**TABLE 3**
**Recommended Actions Based on the Humidex Reading**

| Humidex 1 – Moderate physical work, unacclimatized worker, OR Heavy physical work, acclimatized worker | Response | Humidex 2 – Moderate physical work, acclimatized worker, OR Light physical work, unacclimatized worker |
|---|---|---|
| 25 - 29 | • supply water to workers on an "as needed" basis | 32 - 35 |
| 30 - 33 | • post Heat Stress Alert notice<br>• encourage workers to drink extra water<br>• start recording hourly temperature and relative humidity | 36 - 39 |
| 34 - 37 | • post Heat Stress Warning notice<br>• notify workers that they need to drink extra water<br>• ensure workers are trained to recognize symptoms | 40 - 42 |
| 38 - 39 | • work with 15 minutes relief per hour can continue<br>• provide adequate cool (10 - 15°C) water<br>• at least 1 cup (240 mL) of water every 20 minutes<br>• workers with symptoms should seek medical attention | 43 - 44 |
| 40 - 41 | • work with 30 minutes relief per hour can continue in addition to the provisions listed previously | 45 - 46* |
| 42 - 44 | • if feasible, work with 45 minutes relief per hour can continue in addition to the provisions listed above | 47 - 49 |
| 45 or over | • only medically supervised work can continue | 50* and over |

***High Winds (including thunderstorms, tornados, and hurricanes)***

4.10 Environment and Climate Change Canada issues wind warnings when the wind is sustained at 70 km/h or more, and/or when there are gusts of 90 km/h or more.

4.11 Severe thunderstorm warnings are issued when one or more of the following conditions are met:

- There are wind gusts of 90 km/h or greater;
- Hail of 2 cm or larger in diameter; or
- Heavy rainfall.

4.12 Tornado warnings are issued when a tornado has been reported, or there's evidence of one based on radar.

4.13 Hurricane warnings are issued when hurricane-force gales (sustained winds of 118 km/h or higher) caused by a hurricane, or a strong tropical storm are expected to occur within 24 hours or less.

4.14 When working in extremely high winds, the following guidelines should be followed:

- Stop work when it becomes too dangerous due to high winds;
- In the event of a storm surge due to high winds, avoid coastal areas;
- Secure loose items by bringing indoors or use weights, ropes, etc.;
- Secure latches, doors, windows, etc.;
- Be careful when carrying or lifting large objects such as plywood which can act like a sail;
- Be aware of objects and structures that move suddenly due to the wind;
- Take shelter and stay indoors. Stay away from outside walls and windows, if possible;
- If driving and unable to find shelter, stay in your vehicle. Move to an area where you will be less likely to get hit by falling trees or power lines if possible;
- Keep distance from high vehicles such as transport trucks and buses as strong wind gusts can flip these vehicles;
- Use buildings and vehicles to help block the wind;
- Wear fall protection and secure yourself properly if you are working at heights;
- Wear safety glasses/goggles when it's appropriate;
- Avoid performing lifting operations, using cranes, or doing similar activities;
- If able, avoid working at heights when high winds are forecasted; and
- Do not reach at or try to grab an object that blows away.

<u>Working Aloft</u>

4.15 Working aloft is when work is being performed at a height and involves risk of falling, resulting in an injury. When working aloft in an extreme weather event, the following guidelines should be followed:

- All work should stop when the weather conditions compromise the ability of the workers to safely complete a task. This includes safe operation of tools and equipment, and hazards that might affect the minimum approach distances for workers and/or equipment to energized lines;
- Operating aerial devices with sustained wind or gusts above 80km/h should be considered hazardous unless additional precautions are taken to protect workers and equipment;
- If conditions exist that compromise a worker's ability to safely work aloft, the work should stop until the Incident Prevention Plan can be updated with all workers on site to mitigate hazards;

- At any time when working aloft with high wind conditions that are considered hazardous, the decision to stop work should be made by the worker/workers on site;
- Two or more workers must be present for all work aloft in extreme wind conditions;
- If minimum approach distances cannot be maintained due to the wind, work must stop; and
- Maximum of one worker in the bucket at a time.

***Lightning***

4.16 Lightning is various forms of visible electrical discharge that are produced by thunderstorms; often seen as a bright flash of light in the sky.

4.17 People that are struck by lightning do not carry an electrical charge and can therefore be handled safety. Victims may be suffering from burns or shock and should receive medical attention immediately.

4.18 When Environment and Climate Change Canada issues a thunderstorm warning, or if thunder can be heard, the following guidelines should be followed:

- Stop work and seek to take shelter immediately;
- If far from a shelter, stay away from tall objects such as trees, poles, and fences;
- When in a vehicle, stay inside and do not park under or around tall objects that could fall;
- Avoid being at the highest point in an open area;
- Stay away from water;
- Stay away from objects that conduct electricity, such as objects made of metal;
- Keep alert for flash floods when seeking shelter in a low-lying area;
- Do not go outside unless absolutely necessary; and
- Wait 30 minutes after the last rumble of thunder before going outside.

***Heavy Rain***

4.19 Environment and Climate Change Canada issues heavy rain warnings when 25 mm or more of rain is expected to fall within one hour within Atlantic Canada and northern provinces and territories or when 50 mm or more of rain expected to fall within one hour in other regions of Canada.

4.20 When working during heavy rain, the following guidelines should be followed:

- Reduce the pace of work; rain can cause surfaces, tools, and equipment to become slippery increasing the chances of slipping or dropping objects;
- Take extra care while working or driving as rain causes poor visibility; and
- Try to stay indoors to avoid getting hit by hail. Hail can fall at a great speed, especially when accompanied by high winds.

***Severe winter weather such as snowfall, or ice conditions***

4.21 Environment and Climate Change Canada issues snowfall warnings when 15 cm or more of snow falls within 12 hours or less in Atlantic Canada, Quebec, Ontario, and regions of British Columbia or between 10 cm or 20 cm within other areas of Canada. Winter storm watches or warnings are issued when conditions are favourable for severe and potentially dangerous winter weather including:

- A blizzard;
- A major snowfall of 25 cm or more within 24 hours; and/or
- A significant snowfall combined with other winter weather hazards such as freezing rain, strong wind, blowing snow and/or extreme wind chill.

4.22 The following guidelines should be taken during or after a snowstorm:

- Take extra care while driving. Snow and ice reduces tire traction and falling or blowing snow can decrease visibility; and
- Take extra time and use more caution when doing work if there is low visibility.

4.23 During winter storms where freezing rain is falling, the following guidelines should be followed:

- When outside pay attention to branches and powerlines that could break from the weight of the ice and fall. Ice from freezing rain can accumulate on branches, power lines, and buildings;
- Stay alert after precipitation ends as ice, branches, and powerlines can continue to break for many hours after;
- Try to avoid driving when freezing rain is forecasted, roads can become very slippery from a very small amount of freezing rain; and
- Wear the proper clothing to stay warm as freezing rain mixed with high winds will increase the chances for hypothermia.

***High and Low Atmospheric Pressure Conditions***

4.24 Atmospheric pressure, or air pressure, is the force exerted on a surface by the air above it as gravity pulls it to Earth. Most dangers associated with atmospheric pressure occur at low pressure at very high altitudes, which cannot be reached on Prince Edward Island.

4.25 High atmospheric pressure can cause blood pressure to rise and increase the possibility of heart attacks. Low atmospheric pressure can cause many symptoms such as headache, nausea, fatigue, dizziness, joint pain and shortening of breath. Rapid changes in atmospheric pressure can also induce headaches and migraines. Most people are not overly sensitive to small changes in atmospheric pressure.

4.26 The following guidelines should be used to help reduce symptoms if sensitive to changes in atmospheric pressure:

- Drink more water;
- Avoid foods and drinks that contain caffeine; and
- Try to manage stress through exercise, deep breathing, and relaxation techniques.

***Low Visibility***

4.27 When working while there is low visibility such as darkness, fog, or rain, the following guidelines should be followed:

- Wear high-visibility safety apparel (“HVSA”) especially when working around moving vehicles;
- Make sure that your HVSA is clean and bright. Dirty or faded clothing loses their effectiveness; and
- Take extra time and use more caution when doing work and while driving. If needed, use the vehicle’s fog lights to help with visibility.

## 5.0 APPROVALS

| | | | |
|---|---|---|---|
| **Owner** | *Ken Sampson* | **Date** | *May 6, 2024* |
| **Approver** | *Enrique Riveroll* | **Date** | *May 6, 2024* |

| Effective Date (mm/dd/yr) | Version Number | Individual Making Edits | Reason/Comments |
|---|---|---|---|
| 05/06/2024 | 01 | K. Sampson | New guidelines |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sustainability@maritimeelectric.com


Sustainable Electricity Leader

MARITIME ELECTRIC
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# APPENDIX N

## Transmission Lines Description and Justification

**Title:** **Woodstock Switching Station Transmission Modifications**

**Location:** **Woodstock**

**Line Type:** **Transmission – 69 kV and 138 kV**

**Amount:** **$1,000,000**

**Project Description**

This project involves modifications to connect transmission lines T-21 and Y-115 to the Woodstock switching station. As such, the Woodstock switching station transmission modifications project is interdependent with the Woodstock switching station project as described in Section 6.1a, herein. The combined budget of the two interdependent projects is shown in Table 1.

**TABLE 1**
**Combined Budget of Interdependent Projects**

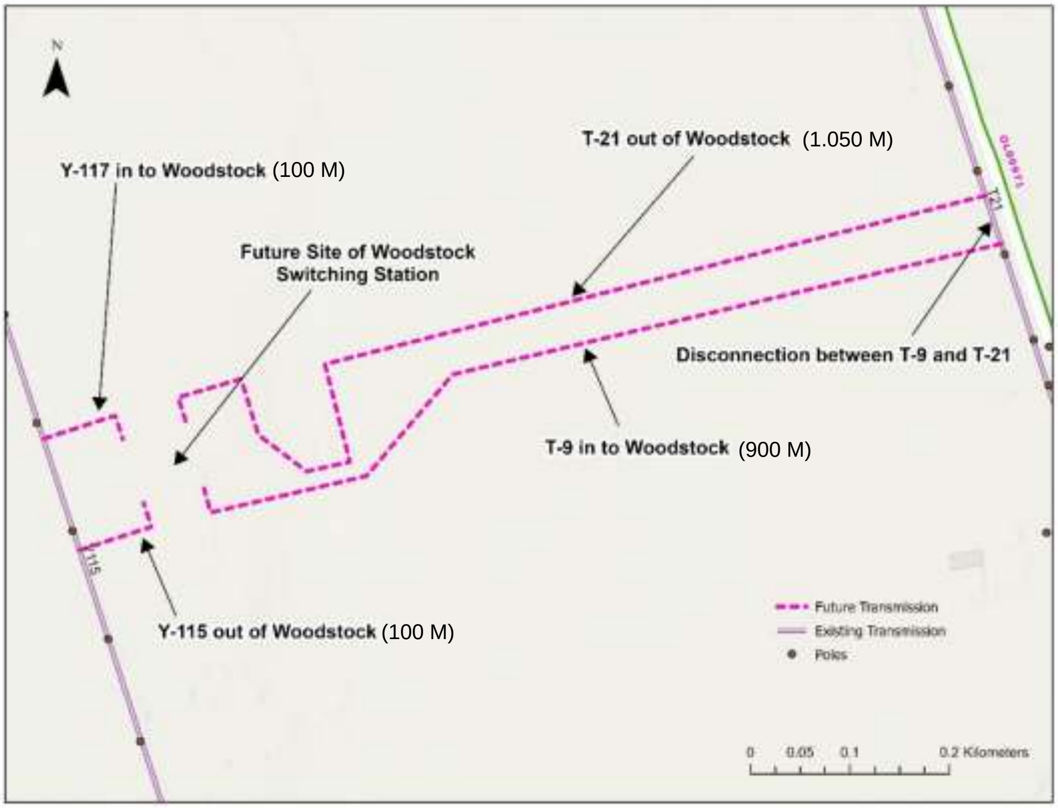
| Description | 2023 (A) | 2024 (B) | 2025 (C) | Budget (D=A+B+C) |
|---|---|---|---|---|
| Woodstock Switching Station Transmission Modifications | $ - | $ - | $ 1,000,000 | $ 1,000,000 |
| Woodstock Switching Station | 1,741,000 | 7,669,000 | 5,161,000 | 14,571,000 |
| **TOTAL** | **$ 1,741,000** | **$ 7,669,000** | **$ 6,161,000** | **$15,571,000** |

The proposed transmission line modifications involve constructing the following line extensions, as shown in Figure 1:

1. A 900 metre ("m") extension of T-21 from Route 2 into the Woodstock switching station (T-9);
2. A 1,050 m extension of T-21 from the Woodstock switching station to the existing line on Route 2;
3. A 100 m extension of Y-115 on the Sherbrooke side of the Woodstock switching station which will establish Y-117;[1] and
4. A 100 m extension of Y-115 on the West Cape side of the Woodstock switching station to continue as Y-115.

[1] Y-115 from Woodstock to Sherbrooke will be renamed as Y-117.

**FIGURE 1**
**Proposed Routing of Woodstock Switching Station Transmission Modifications**




### Justification

The project is justified based on the need to interconnect the new Woodstock switching station with the existing transmission system.

### Costing Methodology

A breakdown of the budget for the Woodstock switching station transmission modifications project is shown in Table 2.

| TABLE 2<br>Breakdown of Proposed Budget<br>Woodstock Switching Station Transmission Modifications | |
|---|---|
| **Description** | **Budget** |
| Material | $ 407,000 |
| Contractor Labour | 245,000 |
| Other (land purchase) | 26,000 |
| Internal Labour and Transportation | 322,000 |
| **TOTAL** | **$ 1,000,000** |

**Construction**

The transmission line modifications will connect T-21 and Y-115 to the new Woodstock switching station. Approximately 1.5 acres of land will need to be purchased at the south end of the switching station property to accommodate the T-21 connection.

Construction is scheduled to begin in the summer of 2025 with 3 crews working for 3 weeks to complete the project. Permits from the Department of Transportation and Infrastructure and the Department of Environment, Energy and Climate Action will be required.

**Alternatives**

There are no alternatives for this project. The line modifications are necessary to connect transmission to the Woodstock switching station.

**Future Commitments**

This is not a multi-year project.

**Title:** **Y-106 Scotchfort to Lorne Valley**

**Location:** **Scotchfort**

**Line Type:** **Transmission – 138 kV**

**Amount:** **$3,192,000 in 2025**

**Project Description**

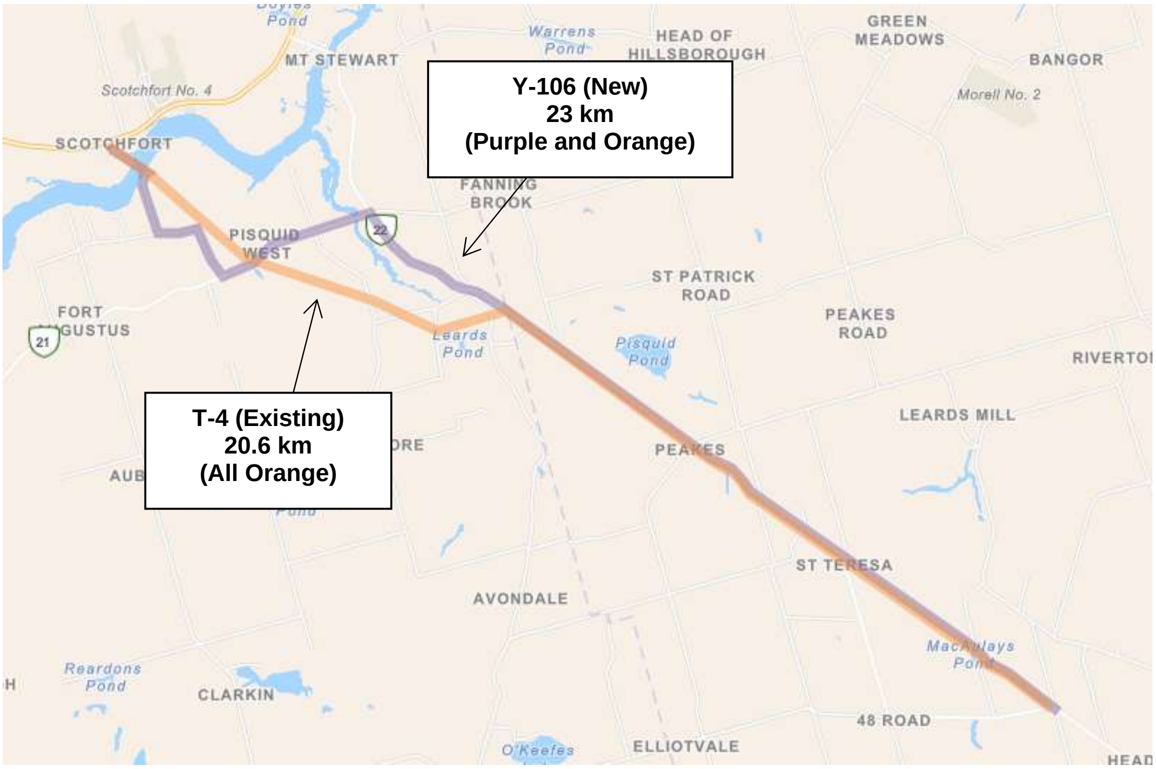
This will be the second year of the Y-106 Scotchfort to Lorne Valley transmission line multi-year project. It is interdependent with the Lorne Valley switching station expansion project as described in Section 6.1b, herein, and the Lorne Valley transmission modifications project which will be included in the 2026 Capital Budget Application. The combined budget of the three interdependent projects is shown in Table 3.

**TABLE 3**
**Combined Budget of Interdependent Projects**

| Description | 2024 | 2025 | 2026 | Budget |
|---|---|---|---|---|
| Y-106 Scotchfort to Lorne Valley | $ 182,000 | $ 3,192,000 | $ 1,707,000 | $ 5,081,000 |
| Lorne Valley Switching Station Expansion | 98,000 | 2,221,000 | 4,820,000 | 7,139,000 |
| Lorne Valley Transmission Modifications | - | - | 640,000 | 640,000 |
| **TOTAL** | **$ 280,000** | **$ 5,413,000** | **$ 7,167,000** | **$12,860,000** |

The project, which involves replacing the existing 69 kV T-4 transmission line with a new 138 kV transmission line, Y-106, to connect to the Lorne Valley switching station, is being completed over three years. In the first year, 2024, the Company is working on engineering design and securing all necessary approvals, which will include the Provincial Government’s environment impact assessment (“EIA”) process. An EIA process is required because the existing off-road section of T-4 will be relocated to a roadside location as shown in Figure 2. This will improve accessibility for construction, inspection, maintenance and repair of the line. Construction of Y-106 will occur over the second and third years of the project, with completion planned for 2026.

**FIGURE 2**
**Proposed Routing of Transmission Line Y-106 from Scotchfort to Lorne Valley**




## Project Justification

T-4 was built in 1969 and currently serves as a dedicated radial connection between the Scotchfort substation and the Lorne Valley switching station. A recent inspection of T-4 confirmed the presence of deteriorated poles, insulators and conductor. Once T-4 is replaced with Y-106 and interconnected to Y-104, the reliability of the transmission system in central and eastern PEI will be improved.

## Costing Methodology

A breakdown of the multi-year budget for the construction of transmission line Y-106 is shown in Table 4.

| TABLE 4<br>Breakdown of Multi-Year Project Budget<br>Y-106 Scotchfort to Lorne Valley | | | | |
|---|---|---|---|---|
| **Description** | **2024** | **2025** | **2026** | **Budget** |
| Design and Permitting | $ 77,000 | $ - | $ - | $ 77,000 |
| Material | - | 1,551,000 | 912,000 | 2,463,000 |
| Contractor Labour | - | 1,439,000 | 654,000 | 2,093,000 |
| Internal Labour and Transportation | 105,000 | 202,000 | 141,000 | 448,000 |
| **TOTAL** | **$ 182,000** | **$3,192,000** | **$1,707,000** | **$5,081,000** |

**Construction**

The existing 4/0 ACSR (Penguin) conductor (rated for 357 amps) will be replaced with 740 Flint conductor (rated for 790 amps). Construction is proposed to be roadside, eliminating 8.25 km of off-road transmission.

In addition to EIA approval, a permit from Department of Transportation and Infrastructure will be required and traffic control will be necessary, as vehicle speed is high along the project route. Work on engineering design and permitting began in the second quarter of 2024 and construction require 5 crews working for a total of 40 weeks over two years, 2025 and 2026.

**Alternatives**

There are no alternatives for this project. The line rebuild is necessary due to the age and condition of T-4 and the upgrade to 138 kV will improve reliability in central and eastern PEI.

**Future Commitments**

This a multi-year project that is to be completed over three years from 2024 to 2026. If there are any changes to the evidence provided herein including changes in scope, budget or timelines subsequent to approval, further evidence will be provided in the 2026 Capital Budget Application.

**Title:** **Y-119 Extension to Scotchfort**

**Location:** **Colville to Scotchfort**

**Line Type:** **Transmission – 138 kV**

**Amount:** **$545,000 in 2025**

**Project Description**

This project involves the extension of transmission line Y-119, from Colville to Scotchfort, over a four-year period. It is interdependent with the new Scotchfort substation project planned for 2025 to 2027, a Scotchfort substation transmission modifications project planned for 2027, and a Y-109 rebuild from Bedeque to Bannockburn Road project planned for 2027 and 2028. See Section 6.1e, herein, for a description of the Scotchfort substation project. A description of the Scotchfort substation transmission modifications project and the Y-109 rebuild from Bedeque to Bannockburn Road project will be provided in the 2027 Capital Budget Application The combined budget of the four interdependent projects is shown in Table 5.

**TABLE 5**
**Combined Budget of Interdependent Projects**

| Description | 2025 | 2026 | 2027 | 2028 | Budget |
|---|---|---|---|---|---|
| Y-119 Extension to Scotchfort | $ 545,000 | $ 4,032,000 | $ 4,071,000 | $ 4,240,000 | $ 12,888,000 |
| Scotchfort Substation | 872,000 | 9,405,000 | 5,917,000 | - | 16,194,000 |
| Y-109 Bedeque to Bannockburn Road | - | - | 5,045,000 | 5,226,000 | 10,271,000 |
| Scotchfort Substation Transmission Modifications | - | - | 421,000 | - | 421,000 |
| **TOTAL** | **$ 1,417,000** | **$ 13,437,000** | **$ 15,454,000** | **$ 9,466,000** | **$ 39,774,000** |

The proposed Y-119 extension will total approximately 54 km, starting at the intersection of Route 225 and Bannockburn Road in Coleville, as shown in Figure 3, and will be routed through Milton, Winsloe, Union Road, Pleasant Grove and Tracadie areas, terminating at the new Scotchfort substation.

The project is planned to be completed over four years from 2025 to 2028. In the first year, 2025, the Company will complete the engineering design and secure all necessary approvals, which includes the Provincial Government’s EIA process. An EIA process is required because the project involves the construction of a new transmission line. Construction will occur over the remaining three years of the project, with completion planned for 2028.

**Justification**

The extension of Y-119 to the new Scotchfort substation is justified based on the obligation to serve load and provide reliable service to customers. Central and eastern PEI, an area which includes 73 per cent of the Company's customers, is currently supplied by two 138 kV transmission lines: Y-109 originating at the Borden substation and Y-111 originating at the Bedeque switching station. Lines Y-109 and Y-111 were added to the system in 1979 and 1987, respectively,[2] and serve to carry power imported from New Brunswick ("NB") via the PEI-NB Interconnection ("Interconnection"), to the majority of PEI's load.

In the 37 years since the last transmission line was added from the Interconnection to central PEI, Island peak load has grown 261 per cent, from 106 MW to 383 MW, the forecast for the upcoming winter. Of the 383 MW forecast peak load, 238 MW will flow through transmission lines Y-109 and Y-111. Should one of these lines suddenly experience an outage, the other line would be required to deliver all 238 MW to the West Royalty substation. While this may be possible without overheating the line, the power quality at the receiving end of the transmission line would not be satisfactory. Furthermore, during forecasted peak, without generation operating in central or eastern PEI, the loss of transmission line Y-109 or Y-111 would result in an outage for approximately 65,000 customers.

The need for a third 138 kV transmission line from the Interconnection to central PEI was identified in the 2020 ISP at loads above 353 MW. When the ISP was being developed, it was forecast that this load level would occur in the year 2027; however, the system has already experienced system peaks in excess of 353 MW, and these load levels are regularly expected in upcoming winters.

To address the concern that Y-109 and Y-111 are not designed to handle the current and forecast future loads, the Company has considered two options: (a) the operation of existing dispatchable on-Island generation (i.e., CT1, CT2 and/or CT3) during high system loads; and (b) the construction of a new transmission line from the Interconnection to central PEI.

[2] Parts of Y-109 are currently retired and are being temporarily served through Y-119.

The first option would deliver power locally and support system power quality, preventing a widespread outage should Y-109 or Y-111 experience an outage. This option may be practical in the short term and will be exercised during the approval and construction period of the Y-119 extension; however, as load grows in the longer term, the number of hours during which generation will be required to operate will increase and become more significant. Fuel costs associated with the operation of on-Island generation during transmission outages is the primary reason why this option was not selected and the second option, a third line from the Interconnection to central PEI, was determined to be the preferred solution.

### Costing Methodology

A breakdown of the multi-year budget for construction of the Y-119 transmission line extension from the Bannockburn Road to Scotchfort is shown in Table 6.

**TABLE 6**
**Breakdown of Multi-Year Project Budget**
**Y-119 Extension to Scotchfort**

| Description | 2025 | 2026 | 2027 | 2028 | Budget |
|---|---|---|---|---|---|
| Design and Permitting | $ 256,000 | $ - | $ - | $ - | $ 256,000 |
| Material | - | 1,607,000 | 1,655,000 | 1,704,000 | 4,966,000 |
| Contractor Labour | - | 1,985,000 | 2,036,000 | 2,087,000 | 6,108,000 |
| Internal Labour and Transportation | 289,000 | 439,000 | 380,000 | 449,000 | 1,557,000 |
| **TOTAL** | **$ 545,000** | **$ 4,031,000** | **$ 4,071,000** | **$ 4,240,000** | **$ 12,887,000** |

### Construction

The Y-119 transmission line extension will be primarily roadside in the public right-of-way and will be constructed with 740 Flint conductor (rated for 790 amps). Vegetation removal, to be completed as required, is included in the project scope.

In addition to EIA approval, a permit from the Department of Transportation and Infrastructure will be required and traffic control will be necessary, given vehicle speeds and traffic volumes along the project route. Engineering design and permitting is scheduled to begin in the first quarter of 2025 and construction will be completed in stages, with 6 crews working for a total of 46 weeks over 3 years, 2026 to 2028.

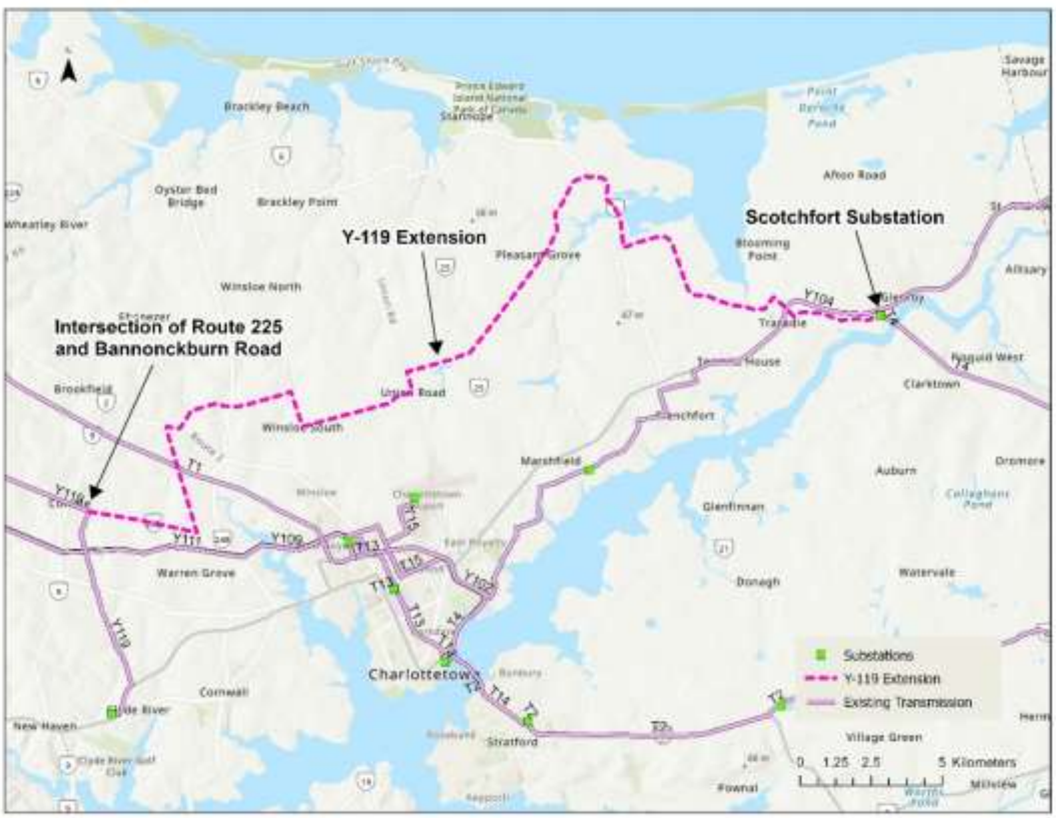
**Alternatives**

There is no practical alternative to completing the project as planned. Deferral by operating the Company's on-Island generation when required due to transmission limitations was considered; however, as load grows and the number of hours during which generation would be required to operate increases, this approach would increasingly result in higher costs for customers.

**Future Commitments**

This is a multi-year project that is proposed to be completed over 4 years from 2025 to 2028. If there are any changes to the evidence provided herein, including changes in scope, budget, or timelines prior to approval, further evidence will be provided in future capital budget applications.

**FIGURE 3**
**Proposed Routing of the Y-119 Extension to Scotchfort**



# APPENDIX O

## Transmission Inspection Deficiencies


*Figure 1*
*Missing hardware*


*Figure 2*
*Splitting in the pole*


*Figure 3*
*Hardware embedded in rotting pole*


*Figure 4*
*Loose hardware on crossarm brace*

# APPENDIX P

## Interest During Construction

IDC, as proposed in Maritime Electric's budget Section 9.0, is calculated on all capital additions except those classified as: (i) distribution transformers; (ii) services and street lighting; (iii) system meters; (iv) distribution equipment; and (v) information technology. The interest rate used in calculating IDC is the annual return on rate base and it is assumed that all applicable project costs are financed over an average 90-day cycle except for multi-year projects which are financed over an average 180-day cycle. The following table shows the calculation of the 2025 IDC budget.

| **2025 Estimated Interest During Construction** | |
|---|---|
| Total Gross Capital Budget including GEC | $ 74,313,000 |
| Less: | |
| 5.2 Distribution Transformers | (15,908,000) |
| 5.3 Services and Street Lighting | (9,702,000) |
| 5.6 System Meters | (805,000) |
| 5.7 Distribution Equipment | (1,573,000) |
| 7.2a Computer Hardware | (832,000) |
| 7.2b Purchased Software and Upgrades | (367,000) |
| 7.2c Cybersecurity Enhancements | (643,000) |
| Multi-Year Projects | (9,847,000) |
| **Total Estimated Regular Capital Subject to IDC** | **$ 34,636,000** |
| | |
| Forecast Average Return on Rate Base[a] | 6.49% |
| Average Number of Days to Finance | 90 |
| **Proposed 2025 Budget for IDC – Regular Capital** | **$ 554,271** |
| | |
| **Multi-Year Projects** | 9,847,000 |
| Forecast Average Return on Rate Base[a] | 6.49% |
| Average Number of Days to Finance | 180 |
| **Proposed 2025 Budget for IDC – Multi-Year Projects Capital** | **$ 315,158** |
| **Proposed 2025 Budget for IDC** | **$ 869,429** |
| **Proposed 2025 Budget for IDC (rounded)** | **$ 869,000** |

a. See Appendix E, page 3 for calculation of 2025 forecast weighted average cost of capital which is equivalent to the forecast average return on rate base.