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MARITIME ELECTRIC
A FORTIS COMPANY

December 20, 2024

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The Island Regulatory and Appeals Commission

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

Dear Ms. Mosher:

2025 Capital Budget Application (UE20741)
Response to Interrogatories from Commission Staff

Please find attached the Company's response to Interrogatories from Commission Staff with respect to the 2025 Capital Budget Application filed on August 2, 2024. An electronic copy will follow shortly.

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

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

GCC29
Enclosure

I N T E R R O G A T O R I E S

Responses to Interrogatories
of
Commission Staff

2025 Capital Budget Application
(UE20741)

Submitted December 20, 2024

IR-1 Please provide a copy of the most recent Distribution Asset Management Program.

Response:

The most recent Distribution Asset Management Program document, dated March 26, 2021, is provided as IR-1 – Attachment 1.

IR-2 Please provide current forecasts for the anticipated capacity related supplemental capital budget request as it relates to the five-year forecast in Appendix A. Please also provide an updated Appendix A that includes all anticipated capital projects and expenditures up to and including 2029. a. Please confirm if the Renewables application mentioned to Commission Staff is included in Appendix A. If not, please ensure it and all other planned projects are included in the updated Appendix A.

Response:

The most recent amendment to Appendix A is provided as IR-2 – Attachment 1. This includes previous amendments filed in response to Roger King's IR-7 filed with the Commission on October 31, 2024, and supplemental capital budget requests that are filed and anticipated to be filed with the Commission, based on current plans and expectations.

IR-3 Please provide a forecast, as of December 31, 2024, of the unspent portion of any previously approved capital budget that MECL intends to carryover to 2025. Please include a forecast of any remaining carryovers from prior years.

Response:

The unspent portion of any previously approved capital budget that Maritime Electric intends to carryover to 2025 is provided as IR-3 – Attachment 1, herein.

IR-4 Customer Contributions are presented as a lump sum deduction to the overall capital budget. Please provide a breakdown of all budgeted customer contributions by project.

Response:

As the Customer Contributions budget is based on a five-year historical average escalated to 2025 dollars, the 2025 Capital Budget Application does not provide a breakdown on a per project basis. However, using 2023 actual per-project Customer Contributions as an indicator, an estimated Customer Contributions per-project breakdown for 2025 is shown in Table 1. Also included is the $100,000 in government funding forecast for the Charlottetown Grid Modernization project.

TABLE 1
Estimated Customer Contributions Breakdown by Project

Year	Replacements due to Storms, Collisions, Fire and Road Alterations	Distribution Transformers	Services and Street Lighting	Line Extensions	Line Rebuilds	Charlottetown Grid Modernization Project	Customer Contributions Total
2023 Actual	$ 53,552	$ 17,608	$ 778,177	$ 395,638	$ 340,881	$ -	$1,585,856
% of Total 2023 Actual (B)	**3%**	**1%**	**49%**	**25%**	**22%**	**-**	**100%**
2025 Budget[1]	-	-	-	-	-	100,000	100,000
2025 Budget[2]	43,500	14,500	710,500	362,500	319,000	-	(A) 1,450,000
TOTALS	**$ 43,500**	**$ 14,500**	**$ 710,500**	**$ 362,500**	**$ 319,000**	**$ 100,000**	**$1,550,000**

1 Charlottetown Grid Modernization Project forecast government funding contribution in 2025.
2 2025 Budget Customer Contributions Total (A) x % of Total 2023 Actual (B), per Project Category.

IR-5 Section 3.3 of the application states that the 2025 capital budget forecast is $7.6 million higher than expected during the recent General Rate Application. MECL expects the incremental increases to be offset through sales growth and operational efficiencies during the remainder of the rate-setting period.

a. Please explain why the forecast is now $7.6 million higher than previously forecast. Include a detailed explanation for the proposed increase.
b. Does MECL expect 100% of the incremental costs to be offset?
c. What operational efficiencies is MECL expecting that will offset this increase? Please include all calculations and assumptions.
d. MECL indicated sales growth would also help offset the increased cost. Please provide MECL's updated forecasts as compared to the General Rate Application.

Response:

a. The $7.6 million amount stated in Section 3.3 of the 2025 Capital Budget Application ("Application") did not consider the 2025 supplemental capital budget request ("SCBR") amount for the Advanced Metering for Sustainable Electrification ("AMSE") project.

To compare the 2025 capital requirement to the most recently filed General Rate Application ("GRA"), the requirement should reflect both the Application and the 2025 SCBR amount for the AMSE project. This is because the 2025 capital budget forecast in the GRA included the estimated 2025 SCBR amount for the AMSE project. As such, the total estimated 2025 capital requirement (including the AMSE SCBR) is approximately $93.6 million, which is $26 million higher than was forecast in the GRA.[3]

Table 2 shows a comparison of the capital budget forecast for 2025 as provided in the GRA to the 2025 total for the Application and the AMSE SCBR. Explanations for significant variances follows.

[3] [$75.2 million (2025 Capital Budget Application) + $18.4 million (AMSE SCBR budget for 2025)] = $93.6 million - $67.6 million (GRA capital forecast for 2025) = $26 million.

TABLE 2 2025 GRA/Capital Budget Application + SBR Comparison and Variance ($000)			
	GRA Capital Forecast for 2025 (A)	2025 Capital Budget Application + AMSE SCBR 2025 Budget (B)	Variance (C = B - A)
4.0 Generation	$ 1,921	$ 1,137	$ (784)
5.0 Distribution	44,171	60,407[4]	16,236
6.0 Transmission	18,441	27,032	8,591
7.0 Corporate	9,062	10,498[5]	1,436
Subtotal	**$ 73,595**	**$ 99,074**	**$ 25,479**
General Expense Capitalized	758	919	161
Interest During Construction	961	2,109[6]	1,148
Customer Contributions	(8,750)	(8,550)[7]	200
Subtotal	**$ 66,564**	**$ 93,552**	**$ 26,988**
Prior Year Carryovers	5,500	-	(5,500)
Carryovers to Following Year	(4,500)	-	4,500
TOTAL	**$ 67,564**	**$ 93,552**	**$ 25,988**

The increased capital requirement of the Application combined with the AMSE project 2025 approved capital spend when compared to the GRA forecast is due primarily to budgeted costs in the Distribution and Transmission categories.[8] To facilitate this response, the total increase for Distribution and Transmission is $24.8 million as shown in Table 3.

[4] Distribution total includes $16,635,000 for the CIS component of the AMSE project, which was not included in the 2025 Capital Budget Application.

[5] 2025 Corporate total includes $7,495,000 for the CIS component of the AMSE project, which was not included in the 2025 Capital Budget Application.

[6] 2025 IDC total includes $1,240,000 for the AMSE project, which was not included in the 2025 Capital Budget Application.

[7] 2025 Customer Contributions total includes ($7,000,000) for the AMSE project, which was not included in the 2025 Capital Budget Application.

[8] The balance of the 2025 Capital Budget categories, including Generation, Corporate, General Expense Capitalized, Interest During Construction and Customer Contributions, have a collective budget requirement that is approximately $1.2 million more than was forecast in the GRA.

TABLE 3 2025 GRA/Capital Budget Application Variance for Distribution and Transmission ($000)			
	GRA 2025 Capital Budget Forecast (A)	2025 Capital Budget Application + AMSE SCBR 2025 Budget (B)	Variance (C = B - A)
Distribution			
5.1 Replacements Due to Storms, Road Alterations	$ 1,796	$ 2,224	$ 428
5.2 Distribution Transformers	9,600	15,908	6,308
5.3 Services and Street Lighting	5,999	9,702	3,703
5.4 Line Extensions	3,522	3,644	122
5.5 Line Rebuilds	6,697	6,813	116
5.6 System Meters	12,551	17,440	4,889
5.7 Distribution Equipment	1,903	1,573	(330)
5.8 Transportation Equipment	2,103	3,103	1,000
Subtotal	**$ 44,171**	**$ 60,407**	**$ 16,236**
Transmission			
6.1 Substation Projects	14,170	19,565	5,395
6.2 Line Projects	4,271	7,467	3,196
Subtotal	**$ 18,441**	**$ 27,032**	**$ 8,591**
TOTAL	**$ 62,612**	**$ 87,439**	**$ 24,827**

In Section 5.0 – Distribution, estimated 2025 costs increased based on information that was not known when the GRA forecast was prepared. Other information on individual project category variances follows.

The costing methodology for Section 5.1 of the Application was revised to calculate the budget based on an inflation adjusted five-year average. This increased the 2025 Distribution budget by approximately $0.4 million.

Distribution transformer per unit pricing and quantity requirement estimates increased the Application amounts for Section 5.2 by approximately $6.3 million. The per unit price increases were due to the industry supply/demand dynamics, and the quantity increases were associated with a growing customer base, and increased electrification, which often requires existing units to be upgraded in size.

The costing methodology for Section 5.3 of the Application was revised to calculate the proposed budget based on an inflation adjusted five-year average, with additional increases allowing for the growing customer base and demand for service upgrades due to electrification. The Application also includes the additional hiring not forecast at the time the GRA was being prepared, to help address the increased demand for new and upgraded services.

The recently approved AMSE project accounts for the Section 5.6 increase of approximately $4.9 million that was not budgeted in the GRA. This is a result of updated budget numbers being submitted to the Commission that align with vendor quotes in April 2024.

Increased budget requirements for Section 5.8 of the Application total approximately $1 million. Estimated costs for transportation equipment purchases have increased from the GRA due to an increase in vehicle pricing and additional transportation equipment required to address the growing electrical system and increased customer demand.

In Section 6.0 – Transmission, estimated 2025 costs also increased based on information that was not known when the GRA forecast was prepared. This information follows.

Advancement of some substation projects to an earlier installation, as well as increased material and equipment prices due to inflation, increased the Section 6.1 budget by approximately $5.4 million. Projects that were advanced included the Lorne Valley switching station expansion, Sherbrooke X1 autotransformer replacement, Scotchfort substation, and power transformer upgrades. Inflation also affected the budget for all Section 6.1 projects as costs for civil construction and sitework, equipment (such as substation transformers), and construction materials all increased at rates above approximately 3 per cent, which would have been the escalation amount used in the GRA.

Changes to timelines for some transmission line projects, increased material and equipment costs due to inflation, and new transmission vegetation management programs increased the Section 6.2 budget for 2025 by approximately $3.2 million. Timeline changes included the Woodstock switching station transmission modifications project moving from 2024 to 2025 and advancing the Y-106 Scotchfort to Lorne Valley project by several years to 2025 due to system load growth. Inflation on transmission poles, conductor and other transmission line materials and equipment also affected the budgets of all Section 6.2 projects that were known at the time the GRA was being prepared, as the approximately 3 per cent escalator used for GRA planning is lower than what has been experienced.

b. Yes, the Company expects 100 per cent of the 2025 annual revenue requirement to be offset by cost savings and sales growth as discussed in responses to IR-5c and IR-5d, herein.

c. The 2025 Employee Future Benefits expense is expected to be lower than the GRA forecast due to amortization of 2022 and 2023 actuarial gains related to its Non-Pension Post-Employment Benefit Plans liability that are being deferred in a Regulatory Deferral Account in accordance with Order UE14-02.

d. Based on most recent forecasts a kWh sales increase in 2025 to approximately 1,606,000 kWh is projected as compared to forecasts for 2025 in the GRA of 1,431,000 kWh, resulting in a kWh increase of approximately 12 per cent.[9] The majority of related sales increases will be offset by energy purchases and related operational expenses required to meet customer needs due to the growth in sales, but it is estimated there will be sufficient margin available to offset the annual depreciation increase resulting from the

[9] (1,606,000 kWh sales new - 2025 forecast / 1,431,000 kWh sales – GRA 2025 forecast = 12.2 per cent.)

variance in the 2025 Capital Budget Application as compared to the forecast previously projected in the GRA.

IR-6 In Appendix E – page 4 – the table references the 2025 revenue requirement per table 6-6 of the GRA is $260,577,000; however, per the General Rate Application the total revenue requirement from basic rates was $256,992,000. In addition, the total revenue requirement per the settlement agreement (Exhibit M-14 of the GRA) is $255,063,000. a. Please explain this variance.

Response:

An amended Appendix E of the 2025 Capital Budget Application ("Application") is provided as IR-6 – Attachment 1. On page 4 of the amended Appendix E, the total revenue is corrected to be $255,063,000, which coincides with GRA Table 6-6.

IR-7 Section 3.7(b) – Provide a detailed comparison of 2023 budgeted labour and transportation costs as compared to actual expenditures in 2023. If there are significant variances, provide a detailed explanation for the variance.

Response:

An internal labour and transportation comparison of budgeted to actual 2023 Capital Budget costs, including comments on material variances (i.e., greater than $30,000 and 15 per cent), is provided as IR-7 – Attachment 1.

As indicated in Section 3.7b of the Application, under Standard Distribution of Costs, internal labour and transportation costs are budgeted using a standard distribution approach based on estimates and/or prior year budgets. During a given budget year, department managers monitor and ensure that internal labour and transportation costs for individual budget items accurately account for the work completed. As Maritime Electric does not use a time tracking system for regular day-to-day work, there is a degree of subjectivity under this approach; however, with managerial monitoring and the use of exception timesheets, standard distribution is a cost-effective approach for allocating internal labour and transportation to operating and capital activities.

IR-8 Section 3.6(c) – Capital Cost Accounting – MECL indicated it follows Canadian private entity Generally Accepted Account Principles ("ASPE") which allows reference to other guidance including accounting principles established in the United States ("US") including Federal Energy Regulatory Commission ("FERC").

For the following projects, please provide justification to support capitalizing the expenditure versus expensing it as an operating expense.

a. Section 4.1(b) ECC Mechanical Upgrades and Electrical Assessment – specifically the Electrical Assessment.
b. Section 5.5(e) Satellite Based Vegetation Imaging – Distribution,
c. Section 6.2(e) Satellite Based Vegetation Imaging – Transmission,
d. Section 7.1(b) Comprehensive Building Condition Assessment, and
e. Section 7.2(c) Cybersecurity Enhancements.

Response:

Generally Accepted Account Principles ("ASPE") Section 3061 establishes the standards for the recognition, measurement presentation and disclosure of property plant and equipment. The definition of Cost 3061.03 (b) "…*is the amount of consideration given up to acquire, construct, develop, or better an item of property, plant and equipment and includes all costs directly attributable to the acquisition, construction, development or betterment of the asset including installing it at the location and in the condition necessary for its intended use…".*

These projects expenditures will provide benefits lasting beyond a single accounting period or year, and be recovered in rates over the benefit period.

a. The ECC building is critical infrastructure that is operational 24 hours a day, 365 days a year, and is essential in the operation of the electrical system.

Replacing the ECC building's 17-year-old HVAC unit with a new unit is a long-term capital investment that will benefit future periods and is not an operating expense because it is not related to the operating expenses of the business day-to-day.

Adding a shower facility to the ECC building is a long-term capital investment that will benefit future periods and is not an operating expense because it is not related to the operating expenses of the business day-to-day. The shower is being added so that ECC operators and other staff are able to stay at the ECC building for extended periods during extreme weather events (i.e., blizzards; hurricanes, etc.) as they sometimes must remain on site to ensure availability for their next shift.

An electrical engineering assessment of the ECC building is a capital investment that will create a foundational plan to determine how the Company should proceed to address the future electrical needs of the facility. This is not an operating expense because it is not related to the operating expenses of the business day-to-day.

b. Section 5.5(e) Satellite Based Vegetation Imaging – Distribution

The satellite-based vegetation imaging program collects satellite imagery and uses an AI technology platform for data-driven risk analysis to optimize vegetation management planning. The program also evaluates and incorporates growth patterns at a discrete level to refine vegetation conditions and risk-of-outage assessments. The purchase and configuration of the program and collection of the imagery for the entire distribution system will occur in the first year to establish a baseline for future years. Year one of this program will be a capital expense as it is similar to information technology projects where the initial purchase and implementation of the solution is capitalized. Each subsequent year, approximately 20 per cent of the imagery files will be updated to establish a five-year cycle for a complete refresh. This update will also be a capital expense as the imagery will have a useful life of five years. Subsequent years will also have an annual operating expense for software maintenance and support, as the software component will be cloud based with annually recurring license fees.

c. Section 6.2(e) Satellite Based Vegetation Imaging – Transmission

The same rationale for capitalizing the Section 5.5(e) Satellite Based Vegetation Imaging – Distribution project, as provided in the response to IR-8(b) herein, also applies to the Section 6.2(e) Satellite Based Vegetation Imaging – Transmission project.

d. Section 7.1(b) Comprehensive Building Condition Assessment

The Comprehensive Building Condition Assessment project expenditures are developmental costs that will become part of the cost of a new asset or betterment to an existing asset. These costs will remain in work in process and become part of the capitalized cost based on the recommendations in the report, that is, cost of renovations or upgrades, or the construction of a new office building. This is not an operating expense because it is not related to the operating expenses of the business day to day.

e. Section 7.2(c) Cybersecurity Enhancements

The category of Cybersecurity Enhancements is a recurring category that encompasses information technology (“IT”) and operation technology (“OT”) projects with cybersecurity benefits. The projects involve the addition of hardware, software and services which improve the cybersecurity posture of the networks. Examples include the replacement of communication equipment in company substations, implementation of a security information and event management solution (centralize solution to collect, analyze and action all cyber and operational alerts) and the implementation of Industrial Security Service (provides intrusion detection and blocks malicious network traffic). Like other IT and OT software, hardware and service investments, the initial purchase and implementation of these solutions is capitalized. These are long term capital investments that will benefit the company in future periods. In the area of software, the ongoing licensing and maintenance is capitalized if it is hosted on premise, or expensed if it is cloud based.

IR-9 Section 4 – Generation – MECL indicated that 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 including requirements set out by the NB Power Purchase Agreement.

a. Please explain if MECL is in compliance with the NB Power Purchase Agreement.
b. If MECL is not in compliance with the NB Power purchase agreement, are there any additional costs to ratepayers?

Response:

a. Maritime Electric is fully compliant with its obligations under the Energy Purchase Agreement ("EPA") signed with NB Energy Marketing in October 2020.

b. There are no additional costs to ratepayers as Maritime Electric is fully compliant with its EPA obligations.

IR-10 Section 5 – Distribution – Explain how the proposed 2025 Capital Budget is in line with the 2020 ISP and with DAMP. Identify any deviations.

Response:

The 2025 Capital Budget is consistent with the Distribution Asset Management Program ("DAMP") through programs and projects that involve distribution asset upgrades and replacements. Examples include the following:

- Replacement of deteriorated and PCB-potential transformers;
- Distribution line rebuilds, voltage conversions, and single to three phase conversions;
- Distribution line inspection and refurbishment activities;
- Distribution corridor widening and satellite-based imaging for vegetation management;
- Targeted asset upgrade and replacement programs for eastern cedar pole replacement, deteriorated conductor replacement, backlot feed relocation, system meters, distribution communications and substation equipment, substation oil containment and substation modernization;
- Distribution equipment life extension or replacement based on maintenance cycles, inspection and quantitative asset testing and evaluation; and
- Replacement, upgrading or addition of substation power transformers where units have reached end of life or maximum capacity.[10]

The 2025 Capital Budget is consistent with the Integrated System Plan ("ISP") through programs and projects that involve generation, distribution and transmission asset additions, upgrades and replacements. Examples include the following:

- Load and reliability driven line extensions and three phase conversions;
- Consideration of sustainability in planning fixed infrastructure and transportation equipment investments, to mitigate against and adapt to climate change;
- The Woodstock switching station and related transmission modifications to improve transmission system reliability and provide voltage support in western PEI;[11]
- The Lorne Valley switching station expansion to improve system reliability and provide voltage support in central and eastern PEI;[12]
- The Sherbrooke X1 autotransformer replacement will replace an existing asset that is now at capacity, in deteriorated condition, and will be 50 years old in 2026;[13]
- Scotchfort substation will replace the existing distribution substation in Scotchfort which is at end of life,[14] and will also serve as a switching point for an expanded east-to-west transmission system (see last bullet, Y-119 extension to Scotchfort);
- Charlottetown grid modernization to design and install distribution automation and communications systems for remote visibility and control of switching, voltage control and other distribution system devices by Energy Control Centre operators;
- Y-106 Scotchfort to Lorne Valley will replace transmission line T-4 which is at end of life, with the rebuilt line upgraded to 138 kV in coordination with the Lorne Valley switching

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[10] The 2025 Capital Budget includes power transformer upgrading/replacement projects for substations in Albany, Kensington, Wellington, Marshfield and Alberton.
[11] This project is referenced in the ISP as the O'Leary/Mount Pleasant 138/69 kV substation.
[12] The ISP indicates a 2027-plus timeline for this project; however, it is occurring earlier to accommodate accelerated system load growth and improve reliability for customers in central and eastern PEI.
[13] The ISP indicates Sherbrooke X1 will be replaced with 75 MVA unit in the 2027 to 2030 timeframe.
[14] The ISP indicates a 2027-plus timeline for this project.

station expansion project.[15]

- Y-119 extension to Scotchfort to provide transmission system voltage support in central and eastern PEI during high load conditions and to avoid system collapse if only one line is operational when system load is above 375 MW.[16]

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15 The ISP does not specify the replacement timeframe for T-4; however, it does note that the line was constructed in 1969.

16 The ISP indicates a 2027 timeline for this project.

IR-11 Section 5.1(b) – Replacements due to Road Alterations:

a. Has the Province of PEI finalized their 2025 plans for infrastructure work since MECL filed their 2025 Capital Budget Application?
b. If so, what (if any) impact does this have on MECL's proposed 2025 budget?

Response:

a. The PEI Department of Transportation and Infrastructure ("PEIDTI") met with Maritime Electric on December 19, 2024, to share its planned projects for 2025. A forecast of priority projects was reviewed with the caveat that the projects discussed were subject to change. Also, as PEIDTI has not yet completed their design work for these projects, it is not known which ones will require power lines to be moved and to what extent.

b. Maritime Electric will be in a better position to estimate the cost associated with each road and bridge project in 2025, after on-site meetings with PEIDTI to review approved designs. If information acquired at these meetings indicates that the 2025 provisional budget amount for replacements due to road alterations will have a variance, the magnitude of the variance will be communicated to the Commission through the Company's quarterly capital expenditure forecasts, as the information becomes available.

IR-12 Section 5.2 – Distribution Transformers:

a. MECL states that the government incentive programs such as the new Oil to Heat Pump Affordability Program is increasing demand and will result in transformer upgrades due to increased energy supply requirements. Please quantify the increased costs imposed on the utility driven by government incentive programs.

b. Considering the increased cost for distribution transformers over the last few years, what has MECL done to mitigate these price increases?

Response:

a. Maritime Electric forecasts an increase of $1,238,000 in the distribution transformer budget for 2025 due to the PEI Government's ("Government") Oil to Heat Pump Affordability ("OHPA") program.[17] This is based on an estimate that approximately 300 polemount transformers will have to be upgraded with a replacement unit due to the OHPA program in 2025.

The budget impact of other Government incentive programs for individual heat pumps and electric vehicle charger installations is harder for the Company to forecast, as they can occur without Maritime Electric involvement. However, because these incentive programs are mostly a continuation of what has been in place for the past several years, historical transformer requirements reflect the impact of these longer-standing incentive programs and as such, they are inherently factored into the distribution transformers budgeting process.

b. To address supply chain issues (and related cost implications) that have limited the availability of distribution transformers over the last few years, the Company has collaborated with another Atlantic utility to create a joint specification and secure multiyear contracts with a preferred manufacturer. This change in the procurement process was made to ensure future supply and help stabilize prices.

In addition, Maritime Electric refurbishes existing transformers where practical, as the cost to refurbish a transformer is less than a new transformer. This serves to reduce the overall budget for transformer additions and is reflected in Table 2 of Confidential Appendix Q–5 of the 2025 Capital Budget Application.

17 $1,238,000 = $4,128 (i.e., average material and internal labour cost of polemount transformers) x 300 (i.e., estimate for number of OHPA program participants requiring a transformer upgrade).

IR-13 Section 5.4(b) – Reliability Driven Line Extensions:

a. Explain how the line extensions will result in reliability improvements? Will these line extensions improve poor performing feeds noted in section 3? Please explain.

Response:

a. In the 2025 Capital Budget Application ("Application"), Section 5.4(b) is titled "Load and Reliability Driven Line Extensions," which is a slight change to the title of "Reliability Driven Line Extensions" that has been used for the past several years. This change was initiated to reflect that line extensions are increasingly required due to customer load growth, as highly loaded single-phase lines are subject to power quality issues and are radially fed, which means that there is no alternate supply option when a line outage occurs. While all single-phase lines are radially fed, if a radially fed line is heavily loaded, more customers are impacted should that line experience an outage. Maritime Electric anticipates that load growth will continue to drive the need for line extension projects over the next several years. These projects also provide reliability benefits, as feeders become more balanced and interconnected.

To maintain reliability and power quality, Maritime Electric's single phase line design amperage limit is 100 amps. Currently, the section of single-phase line to be addressed through this project has reached an estimated line amperage of 153 amps. Converting the single-phase line to three phase, enables the load to be distributed over three conductors (rather than one), thereby reducing amperage on each conductor (or phase) and improving power quality.

The customers in the North Bedeque area are supplied from the Albany substation. During the 2023 polar vortex, these customers experienced poor power quality. The Blue Shank Road three phase conversion project will convert single phase sections of the Bedeque feeder (fed from the Albany substation) and the Norboro feeder (fed from the Kensington substation), so that customers in the North Bedeque area will be supplied from the Kensington substation, to improve power quality.

Improvement in reliability will be realized as this project provides a feeder backup opportunity for maintenance and outage restoration activities, as customers on sections of the Bedeque feeder can be supplied from either the Albany or the Kensington substation.

This project will impact the Bedeque feeder identified in Tables 7 and 8 of Section 3 in the Application. This change will result in improved reliability and power quality. Power quality improvements will be realized as customers will be closer to the substation feeding them, helping to ensure that line voltage is maintained within acceptable limits.

IR-14 Section 5.5(a) – Single Phase and Three Phase Line Rebuilds:

a. What is the average outage hours for customers on each of the line rebuilds as compared to the average MECL customer?

Response:

a. The proposed rebuild projects are required due to these line sections reaching end of life, with both having a high percentage of deteriorated poles, and conductor that is aged and undersized. As such, historical reliability performance is not driving the need for these projects.

The average Maritime Electric customer experienced 4.11 hours of outage (SAIDI - MED Excluded) in 2023.

The outage hours data provided below is specific to each segment of line to be rebuilt and does not include outage hours associated with loss of upstream supply lines. For this and other reasons, it is difficult to compile meaningful comparison data for a typical Maritime Electric customer without significant effort, and even if that were to be done, the result would only be one factor to consider when determining if a line needs to be rebuilt. The decision to rebuild a line is based on reliability statistics, distribution inspection results, asset age, load growth and other operational considerations. As such, reliability is only one component of the analysis.

Customers associated with the Alberton to Elmsdale line rebuild project on AL00200, which feeds AL00261 and AL03066, experienced 0.16 hours of outage (SAIDI – MED Excluded) in 2023.

Customers associated with the Keppoch Road line rebuild project on CR04447, which feeds CR44492, experienced 1.77 hours of outage (SAIDI MED Excluded) in 2023.

As already indicated herein, the two line rebuild projects planned for 2025 are required to replace end-of-life assets. While it is expected that the rebuilt lines will be more reliable than the end-of-life lines, historical reliability performance is not driving the need for these projects.

IR-15 Section 5.5(c)(iii.) – Backlot Feed Relocation Program:

a. Are the lines MECL anticipates relocating at the end of life?
b. Please describe the condition of the lines.
c. Justify the benefits, including a cost benefit analysis, of relocating the lines in the 2025 budget year versus waiting until end of life for each planned line.

Response:

a. Yes, the targeted locations are at or near the end of life, based on age and condition.

b. The poles, insulators and conductors in the targeted areas are approximately 1981 vintage, with some assets recently replaced due to failures, storms, or upgrades. Poles are deteriorated and do not meet current standards for upgraded primary facilities or services. In many cases, poles and conductor are surrounded by trees and other obstructions, such as sheds and fences, which makes access difficult and presents safety concerns that roadside lines do not have.

c. The primary justification for the backlot feed relocation program is to improve public safety and efficient utility access; however, as indicated in the responses to IR-15a and IR-15b herein, the targeted sections of line are at or near end of life.

Proactive replacement and relocation of backlot feed lines and equipment is a lower cost approach than rebuilding in place or eventually replacing all assets on these lines individually as they fail, due to the limited accessibility for line trucks and associated equipment. In addition, backlot feed lines are often problematic during severe weather events as they are often near or through heavy vegetation, which is difficult to manage due to the aforementioned accessibility limitations.

IR-16 Section 5.5(d) – Distribution Corridor Widening & Section 6.2(d) – Transmission Corridor Widening:

a. What is the total vegetation management costs (operating and capital) that MECL is proposing to spend in 2025?
b. MECL states that this is a recurring capital requirement. However, the majority of the recurring work will be performed by contractor (rather than internal) labour. Is this the least cost option? Please provide all supporting calculations/assumptions.
c. How many kilometers of distribution corridor is MECL forecasting to widen in 2025?
d. Please provide a map that identifies the vegetation management that will be completed in the 2024 capital budget, and the vegetation management proposed to be completed in the 2025 capital budget.

Response:

a. In 2025, Maritime Electric is proposing to spend approximately $3.7 million on vegetation management operations and $1.8 million on vegetation management capital work (including $528,000 associated with the new satellite-based vegetation imaging project), for a total vegetation management expenditure of $5.5 million.

b. Continuing to engage contractors for vegetation management is the least cost option. The vegetation management work required for corridor widening is similar to the vegetation management work currently being performed by contractors. Maritime Electric does not have the specialized resources or equipment required to perform extensive vegetation management and would, therefore, require a significant investment in resources, equipment and facilities to perform this work using internal labour. Most neighbouring utilities in the region use this same contractor-based model for vegetation management.

c. Maritime Electric is forecasting to widen approximately 110 kms of distribution corridor and 35 kms of transmission corridor in 2025. This includes some overlap with corridor widening work initiated in 2024, as explained in the response to IR-16d, herein.

d. Figure 1 shows the distribution corridor widening segments that were targeted in 2024 and Figure 2 shows the widening segments that are planned for 2025. Figure 3 shows the transmission corridor widening segments that were targeted in 2024 and Figure 4 shows the widening segments that are planned for 2025.

For 2024, the full lengths of widening segments are indicated, but widening could not be completed throughout, as landowner permission was not granted for some locations within each segment.

For 2025 locations, segments planned for widening are indicated, but the extent to which the work can be completed will be subject to permissions provided from landowners.

There is partial overlap between the 2025 corridor widening work plan and the 2024 work plan. This is because in some cases, two years of work is required to fully complete corridor widening, with aerial trimming and removals occurring in year one, and mechanical mowing occurring in year two.

FIGURE 1
2024 Distribution Widening Program Areas

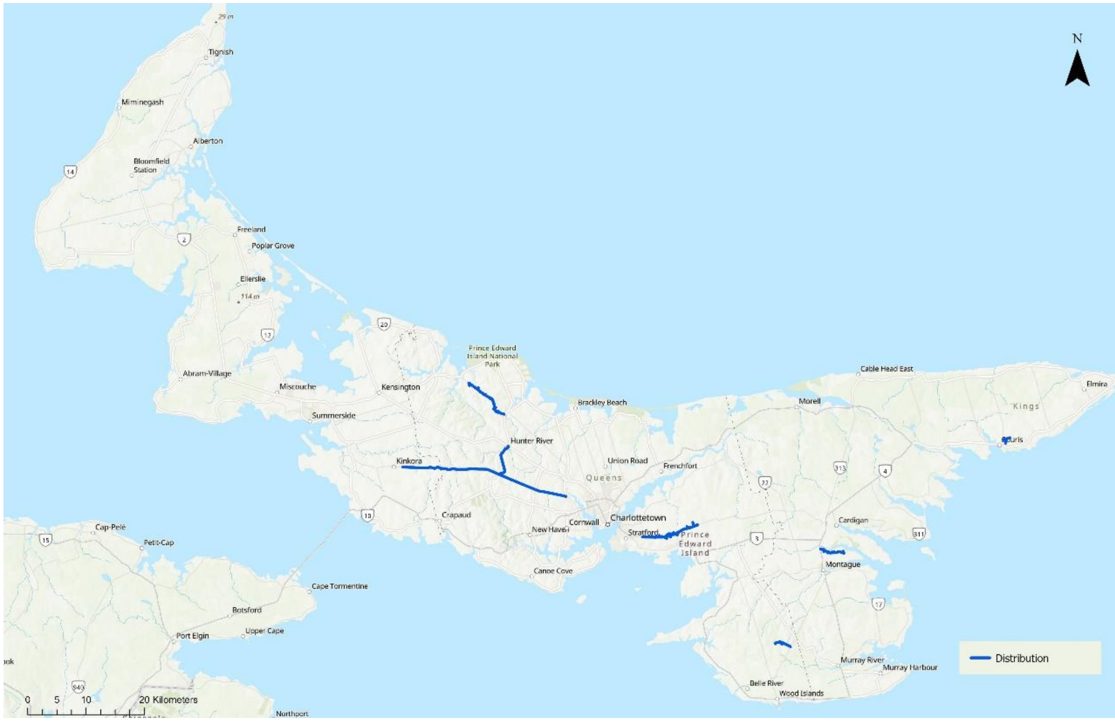


FIGURE 2
2025 Distribution Widening Program Areas

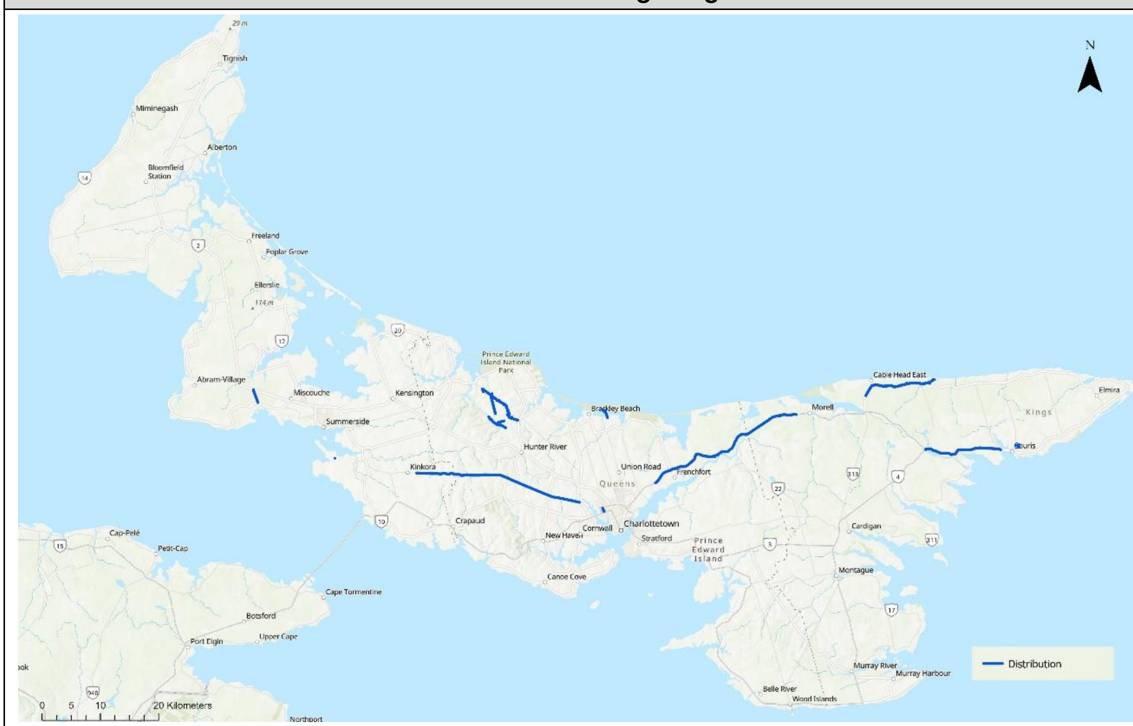


FIGURE 3
2024 Transmission Widening Program Areas

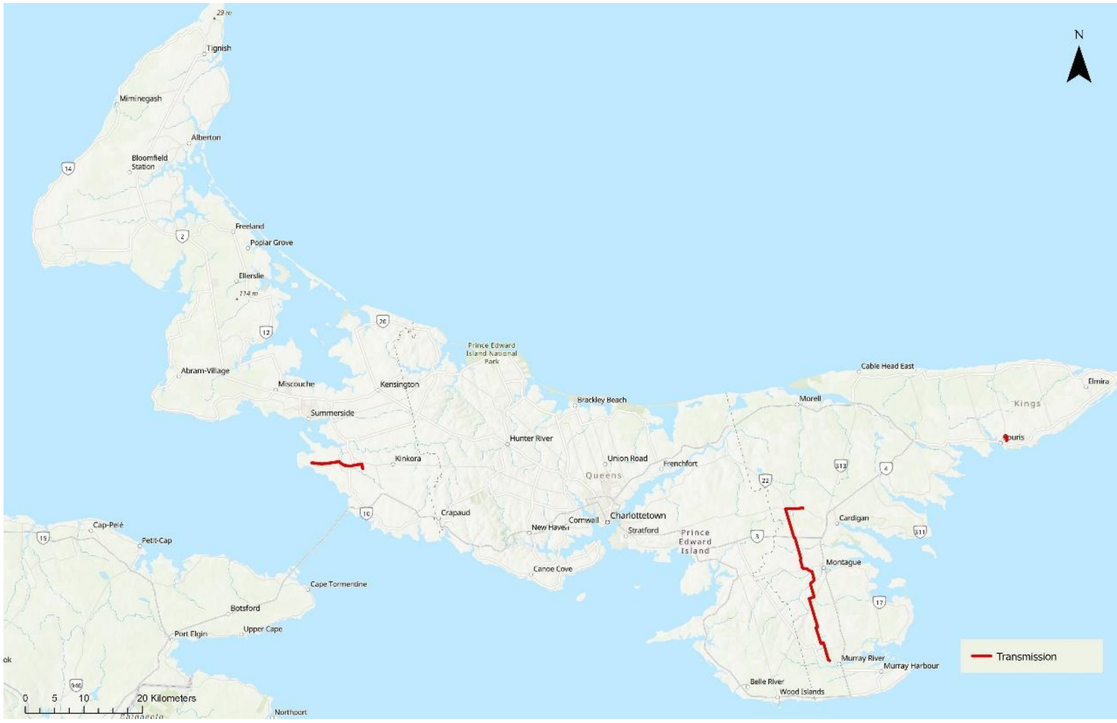
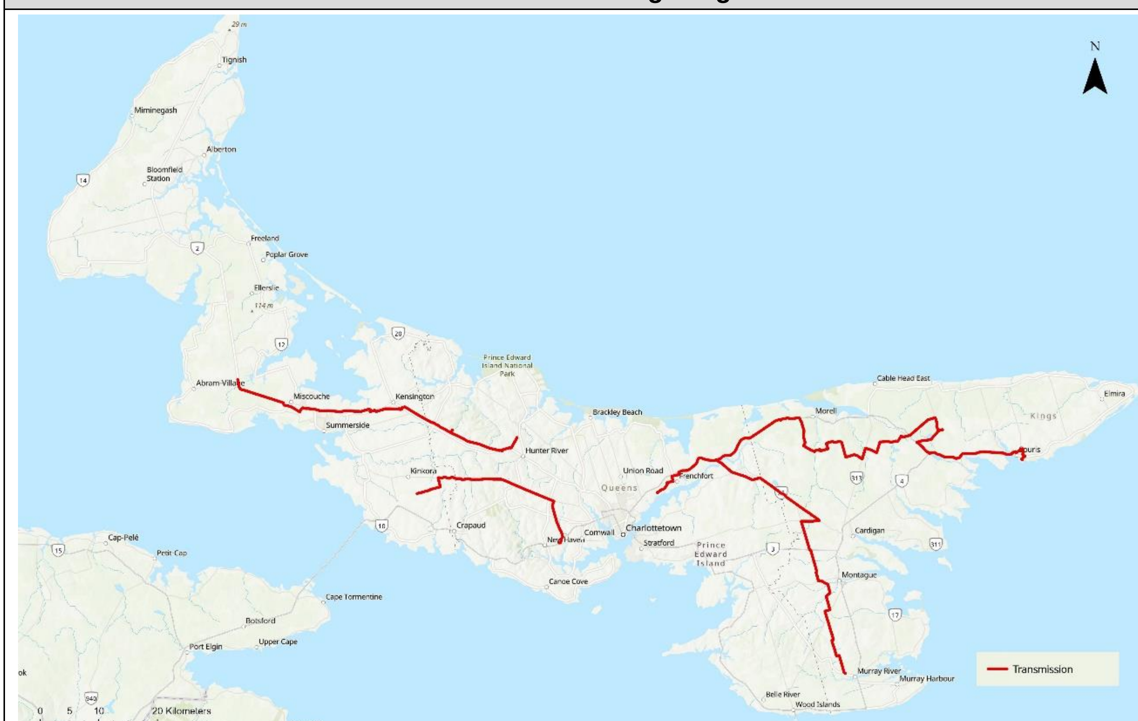


FIGURE 4
2025 Transmission Widening Program Areas



IR-17 Section 5.6 – System Meters – MECL has, subsequent to filing the 2025 Capital Budget Application, received approval for the CIS/AMI Project which includes replacing the current radio frequency meters with smart meters.

a. Please explain if this recent approval affects the budget for system meters. Include all calculations and assumptions.
b. Will radio frequency meters or smart meters be used for new construction in 2025?
c. Please explain how MECL plans to minimize the risk of stranded assets associated with the purchase of additional radio frequency meters in the 2025 capital budget.
d. Please provide additional justification to continue purchasing approximately 1,500 radio frequency meters.

Response:

a. First and foremost, Maritime Electric must ensure it has a sufficient inventory of meters to connect all customers that require service. With the approval of the CIS/AMI project, the Company determined that there are three types of customers where the current inventory of radio frequency ("RF") meters may not be sufficient to connect new customers in 2025: the standard residential customer; the net-metered customer; and customers requiring a combination meter. Therefore, the Company still requires approval of its watt-hour meter budget of $565,000 and the combination meter budget of $90,000. The Company is pursuing options to limit the use of this budget, which is addressed in the response to IR-17c herein.

With respect to the remaining budgets in Section 5.6, namely the outdoor metering tank budget of $110,000 and the miscellaneous metering equipment budget of $40,000, these budgets are not impacted by the CIS/AMI project and continue to need Commission approval.

b The Company's primary plan is to install smart meters once the associated communication systems have been installed and commissioned. The communication systems involve the establishment of the head-end system, the communication modules, the data collectors and the integration to the existing billing system, all of which is necessary for the smart meter to automatically deliver the energy consumption data necessary to produce an accurate and timely bill for customers. It is estimated to take 9 to 12 months to install and commission the communication systems. Therefore, the Company's primary plan is to use RF meters to connect new customers in 2025.

It should be noted that installing smart meters before the communication system has been commissioned would require those meters to be individually read, which would be much more labour intensive than the current drive-by reading of RF meters.

However, the Company is pursuing options to reduce the number of new RF meters required to be purchased in 2025, as discussed in the response to IR-17c herein.

c. The Company plans to closely monitor its inventory of RF meters throughout 2025 and fully deplete that inventory, where possible. One option that the Company is investigating is sourcing RF meters from NB Power or another utility who has recently transitioned from RF meters to smart meters.

While the Company is pursuing every available option, it is still necessary for the watt-hour meter and combination meter budgets to be approved as the Company cannot risk the implications of not having a sufficient supply of meters to connect new customers on a timely basis.

d. As indicated in the response to IR-17a above, in 2025, the Company may not have a sufficient inventory of RF meters to connect all new residential or net-metered customers, or customers requiring combination meters. While the Company will pursue all available options to limit the purchase of new RF meters, the Company has an obligation to connect new customers on a timely basis; therefore, an approval to purchase new RF meters, if required, is necessary.

IR-18 Section 5.7 – Distribution Equipment – Table 49 – The Relay replacement equipment line does not add to $898,000 and the Switch replacement equipment line does not add to $71,000. Subsequently, the total budget line does not add to $1,573,000. Please explain the discrepancy.

a. Similarly, Table 51 is different than the sum calculated in Table 49. Please explain.
b. Table 52 is different than the totals in Table 49. Please explain.

Response:

Please see below the amended Table 49 which agrees to Table 51 and Table 52, and Confidential Appendix Q-8 – Table 1.

TABLE 49 (Amended)
Breakdown of Proposed Budget
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	151,000	33,000	184,000
c. Switch Replacement Equipment	58,000	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**

IR-19 Section 5.8 – Transportation Equipment:

a. Please provide maintenance costs for all proposed replacement vehicles for the previous 3 years.
b. Has MECL completed a cost benefit analysis if their replacement criteria for vehicles was extended? Please provide all calculations and assumptions.
c. During the technical session, MECL indicated they are currently reviewing their replacement criteria with Fortis Alberta. Please provide a comparison between MECL's replacement criteria and those of Fortis Alberta.

Response:

a. Table 4 shows the maintenance costs for the larger line operations replacement vehicles from Table 61 of the 2025 Capital Budget Application ("Application"), and Table 5 shows the smaller passenger vehicles and transportation equipment replacements from Table 62 of the Application.

TABLE 4
Line Operations Vehicles from Table 61
Proposed for Replacement in 2025

Item	Aerial Bucket	Digger/Derrick
Location	Central District	Central District
Vehicle #	15-12-80 (Year 2)	14-12-74 (Year 2)
Chassis Make/Model	Freightliner	Freightliner
Boom Make/Model	Posi + 55 ft Aerial bucket	Altec 50 ft digger/derrick
Description	Chassis and aerial device are a 2015 model. Aerial device is a 55 ft. single person aerial bucket truck.	Chassis and boom are 2014 model. Unit is a 50 ft. digger/derrick truck.
Odometer as of January 2024	172,147 km	134,296 km
PTO or Engine Hours	13,339 Engine hours	8,919 Engine hours
2021 Maintenance Cost	$20,118	$43,591
2022 Maintenance Cost	$31,650	$23,753
2023 Maintenance Cost	$61,884	$47,885
2024 YTD Maintenance Cost	$37,552	$29,914
Approximate Maintenance Costs 2021-2024 YTD	$151,204	$145,143

TABLE 5 Small Vehicles and Transportation Equipment from Table 62 Proposed Replacement in 2025							
Vehicle Description	**Age**	**Odometer**	**2021**	**2022**	**2023**	**2024 YTD**	**Approximate Maintenance Costs 2021–2024 (YTD)**
Chevy Silverado 1/4 Ton Truck	7	118,146	$1,373	$884	$104	$1,626	$3,987
GMC Sierra 1500 1/2 Ton Truck	7	229,760	$1,966	$2,980	$2,046	$8,848	$15,840
Nissan Frontier 1/2 Ton Truck	7	138,068	$5,457	$6,617	$7,647	$3,499	$23,220
Ford F150 1/2 Ton Truck	7	163,000	$4,106	$5,662	$1,714	$1,685	$13,166
GMC Sierra SLE 2500HD 3/4 Ton Truck	7	72,942	$229	$1,559	$1,578	$4,400	$7,766
GMC SIERRA 2500 SLE 3/4 Ton Truck	7	110,757	$2,450	$1,333	$2,568	$657	$7,008
Honda CRV Crossover	6	207,515	$573	$3,489	$860	$2,844	$7,765

b. Maritime Electric has not completed a cost-benefit analysis of extending the replacement criteria for vehicles; however, a comparison of the Company’s replacement criteria (as shown in Table 6) with two neighbouring electric utilities, has been completed. Table 7 shows the vehicle replacement criteria for NB Power and Table 8 shows the criteria for Newfoundland Power.

TABLE 6 Maritime Electric Replacement Criteria for Vehicles	
Tracked Heavy Vehicles	15 years
Heavy/Medium Flat Bed Trucks	10 years or 250,000 km
Heavy Vehicles	10 years or 250,000 km
Service Trucks (CSUP – run double shift) Medium Vehicles	5 years or 250,000 km
Passenger Vehicles	7 years or 200,000 km

TABLE 7 Vehicle Replacement Criteria for New Brunswick Power	
Vehicle Type	**Life Cycle New Brunswick Power**
Radial Boom Digger – Tandem Axle	10 Years or 300,000 km (Evaluate unit condition after 8 years)
Large Aerial Device – Tandem Axle	10 Years or 300,000 km (Evaluate unit condition after 8 years)
Medium Aerial Device – Single Axle	5 Years or 300,000 km
Small Aerial Device – F550 Chassis	8 Years or 300,000 km (Evaluate unit condition after 6 years)
Service Vehicle	6 Years or 250,000 km
Forklift	15 Years (Evaluate unit condition after 13 years)
Trailers (3,501 lb. and above)	12 Years (Evaluate unit condition after 10 years)
Trailers (less than 3,500 lb.)	6 Years
Misc. Offroad Vehicle	15 Years (Evaluate unit condition after 13 years)
ATV/Snowmobiles	5 Years

TABLE 8 Vehicle Replacement Criteria for Newfoundland Power	
Vehicle Type	**Lifecycle**
Aerial Device - Tandem Axle	10 yrs, 250,000 kms
Aerial Device - Single Axle	10 yrs, 250,000 kms
Aerial Device - 5500 Chassis	8 - 10 yrs, 200,000 kms
Pickups/Passenger	5 - 7 yrs, 150,000 kms
Trailer	15 yrs condition based
Misc. Offroad	10 yrs condition based

In general, the replacement criteria for all three utilities was comparable. For example, on a ‘whichever comes first basis’, Newfoundland Power replaces its service vehicles (pickup trucks or small passenger vehicles) every five to seven years or 150,000 km, NB Power replaces service vehicles every six years or 250,000 km and Maritime Electric replaces service vehicles every seven years or 200,000 km. The comparison for large line operation vehicles was similar with all three utilities having an age replacement criteria of ten years and odometer criteria of either 250,000 or 300,000 km, whichever comes first.

c. Table 9 shows a comparison of FortisAlberta and Maritime Electric’s vehicle replacement criteria.

TABLE 9 Comparison of Vehicle Replacement Criteria for FortisAlberta and Maritime Electric by Vehicle Type		
Vehicle Type	Life Cycle	
	FortisAlberta	Maritime Electric
Radial Boom Digger – Tandem Axle	10-12 Years or 10,000 Engine Hours	10 Years or 250,000 km
Large Aerial Device – Tandem Axle	10-12 Years or 10,000 Engine Hours	10 Years or 250,000 km
Medium Aerial Device – Single Axle	10-12 Years or 10,000 Engine Hours	10 Years or 250,000 km
Small Aerial Device – F550 Chassis	5 Years or 220,000 km	5 Years or 250,000 km
Service Vehicle	5 Years or 185,000 km	7 Years or 200,000 km
Forklift	15 Years or Condition Based	Condition Based
Trailer	15 Years or Condition Based	Condition Based
Misc. Offroad Vehicle	10 Years or Condition Based	15 Years or Condition Based

Radial Boom Digger and Large Aerial Devices – Tandem Axle
Medium Aerial Device – Single Axle

For radial boom diggers, large aerial devices, and medium aerial devices, FortisAlberta replacement criteria is based on "years in service" or engine hours, whereas Maritime Electric uses years in service or mileage. Maritime Electric has a slightly shorter years in service criteria (10 years) compared to FortisAlberta (10 to 12 years). This is not unreasonable given that Maritime Electric vehicles are subject to accelerated corrosion from salt air exposure, whereas FortisAlberta's vehicles operate in a somewhat lower humidity and salt air-free environment. Regarding the "engine hours" and "kilometres travelled" criteria, FortisAlberta vehicles typically have on average 150,000 km to 300,000 km travelled (depending on the region where the truck works; rural vs. urban) when they reach 10,000 engine hours.

Small Aerial Device – F550 Chassis Single Axle

Maritime Electric's small aerial device, single axle, has a shorter years-in-service criteria (5 years) compared to FortisAlberta's (10 to 12 years) given that Maritime Electric double-shifts its Customer Service Utility Person ("CSUP") single axle aerial truck. As such, Maritime Electric operates these smaller single-axle trucks 16 hours a day (8:00 am to 4:00 pm and then 4:00 pm to 12:00 midnight), whereas FortisAlberta only operates their trucks 8 hours per day. On this basis, Maritime Electric's F550 single axle will achieve the same mileage as the FortisAlberta truck in half the time.

Service Vehicle (Maritime Electric small passenger vehicle equivalent)
For service vehicles, Maritime Electric has a slightly longer years in service criteria (7 years) compared to FortisAlberta (5 years), and slightly higher mileage criteria of 200,000 km versus 185,000 km for FortisAlberta.

Forklift
Maritime Electric does not have a years-in-service criteria for forklifts whereas FortisAlberta's is 15 years. Instead, Maritime Electric forklift replacement decisions are solely based on condition assessment. As forklift operating conditions are conducive to a long service life, Maritime Electric has some units still operating that are over 30 years old.

Trailers
Maritime Electric also makes trailer replacement decisions based on condition assessment rather than specific replacement criteria. There are 38 trailers of various types in the Company fleet (e.g., pole trailers, wire trailers, off-road equipment trailers, etc.), with an average in-service life of 24 years.

Miscellaneous Offroad Vehicles
For the replacement of offroad vehicles, Maritime Electric's years in service criteria (15 years) is higher than used by FortisAlberta (10 years). Both utilities also make offroad vehicle replacement decisions based on condition assessment due to the rugged service environments they are currently exposed to. A mileage limit is not a practical measure for offroad vehicles, as most would have low kilometres given the nature of offroad work.

IR-20 Section 6 – Transmission:

a. Which of these capital expenses does MECL intend to recover from transmission customers as part of the next OATT schedule update?
b. What is the resulting impact for transmission customers? Assume all proposed capital expenditures are approved and recovered under the OATT as proposed by MECL.

Response:

a. Table 10 lists transmission projects included in Section 6.1 – Substation Projects and Section 6.2 – Transmission Projects of the 2025 Capital Budget Application, along with the respective budget and Open Access Transmission Tariff ("OATT") costs for each project.

TABLE 10
Breakdown of Proposed Budget
Transmission Projects

Item	Description	Budget	Incremental Costs to OATT
6.1a	Woodstock Switching Station	$ 5,161,000	$ 5,161,000
6.1b	Lorne Valley Switching Station Expansion	2,221,000	2,221,000
6.1c	Sherbrooke X1 Autotransformer Replacement	3,184,000	3,184,000
6.1d	West Royalty 13.8 kV Distribution Replacements	1,777,000	-
6.1e	Scotchfort Substation	872,000	436,000
6.1f	Charlottetown Grid Modernization	200,000	-
6.1g	Power Transformers	3,943,000	-
6.1h	Substation Oil Containment Program	176,000	176,000
6.1i	Substation Modernization Program	560,000	-
6.1j	138 kV Breaker Program	146,000	146,000
6.1k	Communication Fibre – Church Road to Souris	1,279,000	-
6.1l	Fibre Modifications Due to Road Alterations	46,000	-
6.2a	69 kV and 138 kV Switch Program	1,186,000	1,186,000
6.2b	Transmission Line Refurbishment	1,031,000	1,031,000
6.2c	Transmission Lines	4,737,000	4,737,000
6.2d	Transmission Corridor Widening	381,000	381,000
6.2e	Satellite-Based Vegetation Imaging - Transmission	132,000	132,000
TOTAL		**$ 27,032,000**	**$ 18,791,000**

The OATT defines the terms, conditions and price for third-party access to Maritime Electric's transmission system on the same basis as the Company uses the transmission system for serving its own load. As such, any costs associated with operating or maintaining the transmission system are to be included in OATT rates.

Referring to Table 10, for each of the transmission projects listed, a brief justification for its inclusion in, or exclusion from, OATT charges, follows.

6.1a The Woodstock switching station is a new transmission substation justified on the need to improve voltage support and reliability of the transmission system in western PEI. All of the costs indicated in the Application for the Woodstock switching station will be recovered through OATT rates.

6.1b The Lorne Valley switching station is an existing transmission system facility in eastern PEI. Increased loads are driving the need to offload autotransformers in West Royalty and provide increased voltage support in central and eastern PEI. All of the costs indicated in the Application for the Lorne Valley switching station will be recovered through OATT rates.

6.1c The Sherbrooke X1 autotransformer is a transmission system asset in western PEI. Sherbrooke X1 needs to be replaced as it is approaching end of life and cannot prudently be operated to failure. All of the costs indicated in the Application for the Sherbrooke X1 autotransformer replacement will be recovered through OATT rates.

6.1d The West Royalty substation 13.8 kV distribution replacements project primarily involves the replacement of assets that are not part of the transmission system and therefore the costs will not be included in OATT rates.

6.1e The Scotchfort substation project involves the replacement of the existing Scotchfort substation and the construction of new 138 kV transmission switching yard. Costs associated with the distribution substation replacement are not transmission additions and will not be included in OATT rates, whereas costs associated with the new transmission yard are transmission additions that will be included in OATT rates. Until the specific breakdown of distribution and transmission costs is determined through the engineering design process, it is assumed that 50 per cent of the project will involve transmission additions that will be recovered through OATT rates.

6.1f The Charlottetown grid modernization project primarily involves upgrades to the distribution system and therefore costs will not be included in OATT rates.

6.1g All five power transformers required are distribution system transformers for stepping the voltage down from 138 kV or 69 kV to 12.5 kV to serve local load. As such, these power transformers are not considered a part of the transmission system and will not be included in OATT rates.

6.1h The substation oil containment program is focused on reducing transformer oil spills. The transformer location to be upgraded in 2025 is at the Church Road substation, which is a transmission system asset (138 kV to 69 kV) and therefore, the costs will be included in OATT rates.

6.1i The substation modernization program is an annual program focused on upgrading deteriorated and substandard substation infrastructure. The program is focused primarily on distribution substations; therefore, it is expected that the costs will not be included in OATT rates.

6.1j The 138 kV breaker program is focused on replacing 138 kV high voltage circuit breakers and in 2025, the breaker for transmission line Y-111 will be replaced due to age. This breaker is considered a transmission asset and therefore the costs will be recovered through OATT rates.

6.1k The Church Road to Souris communication fibre project is required to serve the Souris substation, which is a distribution facility. As such, project costs will not be considered as transmission additions and will not be recovered through OATT rates.

6.1l Fibre modifications due to road alterations is a provisional budget that is used when fibre changes associated with both transmission and distribution assets occur. Generally, distribution fibre modification is more common; therefore, it is expected that these costs will not be included in OATT rates. However, as costs are incurred, they will be tracked and any costs associated with transmission assets will be recovered through future OATT rates.

6.2a The 69 kV and 138 kV switch program is focused on upgrading or replacing 69 and 138 kV transmission line switches. The Company identified the requirement to purchase six transmission switches and accessories with two 69 kV switches for Alberton substation, two 69 kV switches for UPEI substation, and two switches (one 69 kV and one 138 kV) to have available for emergency backup replacement. As such, program costs are considered transmission additions and will be recovered through OATT rates.

6.2b The transmission line refurbishment program provides budget for inspection and capital repair/replacement of priority deficiencies found on transmission lines. The costs are considered transmission additions and will be recovered through OATT rates.

6.2c There are three transmission line projects planned for 2025: Woodstock switching station transmission modifications; Y-106 Scotchfort to Lorne Valley; and Y-119 extension to Scotchfort. The costs for all three projects are considered transmission additions and will be recovered thorough OATT rates.

6.2d The corridor widening program for transmission is required to remove vegetation along existing transmission lines. As there is a separate budget amount for distribution corridor widening, the costs of this program are considered transmission additions and will be recovered through OATT rates.

6.2e The satellite-based vegetation imaging program for transmission is required to collect and process vegetation imaging data along existing transmission lines. As there is a separate budget amount for distribution satellite imaging, the cost of the program are considered transmission additions and will be recovered through OATT rates.

b. As shown in Table 11, the total expected capital costs for transmission projects included in the Application and intended to be recovered through OATT rates is $18,791,000.[18]

The annual financial impact resulting from these capital costs is approximately $1.8 million in year one.[19] This increase in costs would result in an approximate 9.6 per cent increase to OATT rates.

TABLE 11
Estimation of the Increase to OATT Rates
Associated with the 2025 Capital Budget

Item	Cost	Formula
Total Cost of 2025 OATT Capital Projects	$ 18,791,000	
Financial Impact of 2025 OATT Capital Projects	1,750,325	A
2023 OATT Revenue Requirement[20]	18,172,000	B
Per Cent Increase of Revenue Requirement due to 2025 OATT Capital Projects	9.6 %	= A / B * 100

18 The total of $18,791,000 includes 2025 spending only. Several projects included in this total are multi-year projects but only the 2025 portion of spending has been included.
19 This is an approximation only. Several projects included in this total capital cost are multi-year projects. Multi-year projects would not be included in OATT rates until the projects are completed and assets are considered used and useful. This cost also includes financing, corporate taxes, and amortization costs for the capital but does not include operation and maintenance costs.
20 Refer to the revised 2023 OATT schedule update filed under docket number UE20947.

IR-21 Section 6.1(d) – West Royalty Substation 13.8 kV Distribution Replacements Program is a multi-year project with a budget of $1.7 million in year 1 and a total budget of $12.7 million.

a. Please provide additional detailed justification for this project and any related interdependent projects.
b. Are there any projects that are interdependent with this project?
c. Please provide a summary of the benefits this project and its related interdependent projects will have on the electric grid. Include reliability improvements, resiliency improvements, customer benefits, etc.

Response:

a. The 13.8 kV power transformers, switchgear, and underground cables in the West Royalty substation have all reached end of its useful life. The primary justification for this project is to address the increased probability of failure of critical substation components such as transformers, switchgear, and underground cables.

Power transformers are the most critical pieces of equipment within a substation. A transformer consulting service provided the following diagnosis on the two units serving the 13.8kV load in West Royalty, after reviewing dissolved gas analysis (“DGA”) results.

> “The 2015 DGA shows the levels of carbon gases approaching the threshold but subsequent years these levels decrease. The General Oil Quality (“GOQ”) Color at 3.0 indicates a darkened oil indicative of overheating and insulation degradation.”

Degraded insulation in a power transformer translates to an increased probability that a conductor fault in the transformer will cause a catastrophic failure. The insulated conductor experiencing the degradation is coiled around the steel core inside of the transformer and is submerged in oil, making the cost and time to repair not a practical solution.

The 13.8 kV underground cables and switchgear at West Royalty has recently experienced failures. Figure 5 shows a cable termination failure, where the oil immersed paper insulation is burnt off the termination with the exposed conductor on the right-hand side. Repairing the damaged insulation on the termination required specialized expertise that was not readily available and required several months to secure. Figure 6 shows an arcing failure that resulted in the black line on the insulator, which required de-energization and reconnection of the termination. If this had not been identified in an inspection, the whole termination might have required replacement. These types of failures are reasonably expected due to the age of the equipment and due to load growth, would result in customer outages should they occur during high load periods.

When critical system component failures occur, there is a direct reliability impact as customers downstream of the asset are disconnected. When the cause of the failure cannot be repaired in the short term (e.g., when specialized expertise is not readily available), power must be restored using a neighboring circuit, if possible. This, in turn, then results in a higher number of customers being serviced from an individual circuit, putting the reliability of the backup circuit at elevated risk.

FIGURE 5 Cable Termination Failure	FIGURE 6 Arcing Failure within the 13.8kV Switchgear
	

b. There are no interdependent projects associated with this project.

c. The primary reliability improvement of the project will be the replacement of end-of-life substation components that are at an elevated risk of failure, with new components that are at minimal risk of failure. The new and upgraded substation component will also provide resiliency improvements as they will be sized for higher loads and configured to meet current substation design standards. The addition of circuit breakers on the 69 kV bus side of the two new proposed power transformers, will allow for isolation of the units without impacting West Royalty's 69 kV bus. This increases reliability by eliminating the need to interrupt transmission lines feeding UPEI, Airport, Hunter River, and Bagnall Road substations in the event of a power transformer fault.

IR-22 Section 6.1(e) – Scotchfort Substation is a multi-year project with a budget of $872,000 in year 1 and a total budget of $16.2 million. This project is also interdependent on 3 other projects, the total budget for all 4 projects over 4 years is $39.8 million.

a. Please provide additional detailed justification for this project and the related interdependent projects.
b. Is this the least cost alternative to replace the existing Scotchfort substation? Please include analysis and assumptions.
c. Please provide a summary of the benefits this project and its related interdependent projects will have on the electric grid. Include reliability improvements, resiliency improvements, customer benefits, etc.

Response:

a. The Scotchfort substation project will serve as a replacement for the existing Scotchfort substation, which was built in the late 1960's, and as a switching point for the interconnection of four 138 kV transmission lines, including the addition of a third 138 kV west to east transmission line from Borden substation. Establishing a third 138 kV west to east transmission line involves two projects, the Y-119 Extension to Scotchfort project and the Y-109 Bedeque to Bannockburn Road project. Transmission modifications to connect three other existing lines to the new Scotchfort substation will also be required.

The project, along with its interdependent projects, is required for two reasons.

1. To provide system support to eastern and central PEI during reasonably expected system events.

   As indicated in Appendix B of the 2020 Integrated System Plan, a third 138 kV west to east transmission line is required when the Island load is above 353 MW. The forecasted Island peak load for 2025 is 383 MW. Additional justification for the third west to east line is provided in the Y-119 Extension to Scotchfort project description, included in Appendix N of the 2025 Capital Budget Application ("Application").

   To establish the third 138 kV west to east transmission line, a new substation, or significant modifications to an existing substation, is required. As described in Section 6.1(e) of the Application, the West Royalty substation was considered, but it was determined that a switching yard in the new Scotchfort substation provides a more reliable and reasonable solution.

2. To replace the existing Scotchfort substation.

   The existing Scotchfort substation has reached the end of its useful life and no longer meets modern substation safety clearances. The Company explored options to extend the life of the existing Scotchfort substation and to modify it to meet modern safety clearances, but physical constraints limit the ability to do so. As such, it is believed that a larger property that can accommodate the switching yard would be the best option.

b. During the Company's capital planning process, the need for a switching point to connect the third 138 kV west to east transmission line was identified. The Company also identified that the Scotchfort substation was approaching the end of its useful life and required replacement. For construction efficiency and to minimize costs, it was decided to develop both projects at one site. While a new substation with distribution feeders and transmission switching is more costly than a distribution-only substation, two standalone sites would be more costly and, as such, not the least cost solution.

c. The benefits of the proposed Scotchfort substation and interdependent projects follow.

1. Provides system support to central and eastern PEI during reasonably expected system events.

   The switching yard component of the Scotchfort substation project will enable the addition of the third 138 kV west to east transmission line to the electrical system. Without this new line, customers in central and eastern PEI will be exposed to brownouts or blackouts should either Y-109, Y-111, Y-102, or Y-104 trip unexpectedly during high load periods.

   Good utility planning practice expects that the loss of a single networked transmission line can be managed without impacting customers. At load levels expected in winter 2025 and onwards, this would not be the case with the loss of Y-109, Y-111, Y-102, or Y-104 during peak load periods without preemptively operating generation, which is costly.

   The addition of the third 138 kV west to east transmission line will provide an alternate path for power to flow should one of the aforementioned lines trip unexpectedly, enabling the electrical system to manage the trip without impacting customers. As such, the line will improve system resiliency and reliability for all customers in central and eastern PEI.

2. Replaces the existing Scotchfort substation.

   The existing Scotchfort substation has reached the end of its useful life, and was built to an older, now out-of-date construction standard. As such, the station is not as resilient as a modern substation. The new substation will meet modern safety standards, providing benefits for Maritime Electric employees and contractors. Increased clearances within the new substation will allow work to be completed more safely and it will be upgraded to include a mobile transformer bay, transfer bus, and modern monitoring equipment with full telemetry, which the current substation does not have.

   The existing Scotchfort substation currently has just one connection to the transmission system through T-4. T-4 has reached the end of its useful life and is currently being replaced and upgraded by Y-106. The new Scotchfort substation will be connected directly to the switching yard that will form part of the substation. This will provide a high level of reliability to the customers served from the substation as it will have four supply sources, including Bedeque switching station, West Royalty substation, Lorne Valley substation and Church Road substation.

IR-23 Section 6.1(f) – Charlottetown Grid Modernization – This is a proposed pilot project costing $4 million over a 4 year period. MECL indicated they have applied for government funding that could fund approximately half of the project costs.

a. Please provide additional justification for this project if the government funding is not approved.
b. What is the expected cost savings and/or customer benefits?
c. Is this the least cost option for customers? Please explain.
d. If successful will this program be proposed for other areas of the transmission system?

Response:

a. Response filed as a IR-23a – Confidential Attachment 1.

b. The Charlottetown grid modernization project will enable real-time remote monitoring and control to minimize outage response time and improve power quality in the city core. The Project will result in operational cost savings by reducing expenses associated with dispatching crews for line patrols and fault detection. The project will also investigate the use of the third-party cellular system as an alternative communication method.

c. The integration of distribution automation projects is recognized as good utility practice. This technology is proven with a demonstrated ability to improve the reliability and resiliency of the distribution system. The opportunity to pilot distribution automation with funding assistance will enable the project to be completed at least cost for customers and help to ensure that future similar projects will provide cost saving benefits to customers through the learnings and successes of the pilot.

d. As the project progresses, Maritime Electric will evaluate and expand this technology across the province on the distribution system in applicable areas.

IR-24 Section 7.2(c) – Cybersecurity Enhancements – In 2021, 2022, 2023 and 2024, there are increased expenditures on Cybersecurity Enhancements. Please distinguish between the Cybersecurity Enhancements undertaken in prior years versus those proposed for 2025.

Response:

Maritime Electric has two computer networks. They are:

1. An IT network, which supports email, file access and business systems for billing, outage management, customer service, website hosting, etc.; and
2. An OT network, which supports the management and operation of the electrical grid, communication to substations, system monitoring and control, and system safety.

Maritime Electric's IT department is responsible for cybersecurity on both networks. This responsibility involves ensuring that the Company is always current in its awareness of the cyber risks that could damage its networks, and that it has the cyber controls in place to protect against those risks.

In the 2021 Capital Budget, three projects in Section 7.2 – Information Technology addressed cybersecurity as follows:

- 7.2d – Business Network Security Review
- 7.2e – Cybersecurity Enhancements
- 7.2f – Operations Network Data Centre Infrastructure.

The three projects had a total combined budget of $662,000.

In the 2022 to 2025 capital budget applications, Maritime Electric consolidated all proposed cybersecurity enhancement activities into Section 7.2c – Cybersecurity Enhancements, with a proposed budget of $547,000, $572,000, $787,000 and $643,000, respectively. For clarity, Section 7.2c – Cybersecurity Enhancements in the 2022 to 2025 capital budget applications includes similar activities to what had previously been undertaken through three separate projects in 2021.

While there are many similarities in the investments required to ensure the security of Maritime Electric's computer networks since 2021, there are also some activities that are unique to just one year. A breakdown of the cybersecurity enhancements undertaken from 2021 to 2025 is as follows.

Cybersecurity enhancements common to 2021, 2022, 2023, 2024 and 2025:

- A review of the IT network by an external security specialist, [21] with recommendations from the review for replacing or updating hardware, software, tools and configurations acted upon in each year.
- Purchase and deployment of software applications to enhance personal computer ("PC") end-point protection and manage privileged network access within the IT team.

[21] In the 2021 Capital Budget Application, this activity was included as 7.2d - Business Network Security Review.

Cybersecurity enhancements common to 2023 and 2024:

- Implementation of a security information and event management ("SIEM") solution in the IT environment to augment the recent investment in existing independent alerting and event end-point software. The SIEM will aid in the speed and accuracy of incident response by providing a centralized solution to collect, analyze and action all cyber and operational alerts from IT systems and applications.

Cybersecurity enhancements unique to 2021:

- Purchase and installation of equipment required to secure the OT network in accordance with the Company's CRMP.
- Purchase and implementation of software to replace the majority of IT network legacy servers and services that relied upon platforms no longer supported by the vendor.
- Purchase and deployment of enhanced encryption software for all of the Company's PC end-point assets.

Cybersecurity enhancements unique to 2022:

- Purchase and implementation of IT network software to provide enhanced security information and cyber-event management.
- Establishment of foundational cybersecurity controls for the OT network, including purchasing and deploying software for:
  - Centralized cyber-event retention and alerting;
  - Controls PC end-point protection and segmentation;
  - Management of network access restrictions; and
  - Network traffic inspection and control within and between OT substations.

Cybersecurity enhancements unique to 2023:

- Upgrades to the OT network in 2021 and 2022 have brought it to a level where an annual security review will add value. An annual security review was performed on the OT network, as well as the remediation work from the findings of the review.
- Improvements to the IT network's domain name system ("DNS") inspection and filtering capabilities. DNS is the process that translates internet website requests (e.g., www.maritimeelectric.com) to internet protocol addresses (e.g., 104.104.103.240). DNS traffic is commonly attacked and abused by cyber criminals.
- The implementation of a vulnerability management software ("VMS") on the OT network. VMS proactively identifies weaknesses by scanning a network and then providing remediation suggestions to mitigate potential risks.
- The implementation of extensive inspection and filtering for OT network traffic. This project will provide further inspection and filtering of network traffic occurring within an OT site (e.g., a substation) and between sites beyond the existing controls which are in place for traffic traversing the perimeters of the IT and OT networks.

Cybersecurity enhancements unique to 2024:

- A refresh of the IT firewall infrastructure to provide continued support along with increased telemetry and health data for connected endpoints.

- The OT Cyber Team will install new communication equipment in two substations.
- The implementation of FortiGuard Industrial Security Service (“ISS”). The FortiGuard ISS provides specialized intrusion prevention system signatures to detect and block malicious traffic.

Cybersecurity enhancements unique to 2025:

- A refresh of the Network Access Control (“NAC”) technology that has been in place for five years and is due for replacement. A NAC solution protects against unauthorized or insecure devices from accessing the computer network. The system only permits Maritime Electric devices to be acknowledged on the network.
- With the completion of the substation communication refresh project in 2024, the platform is now in place to implement substation asset management and monitoring software. This has been completed at four substations and will be expended to an additional ten substations in 2025.

I N T E R R O G A T O R I E S

IR-1 – Attachment 1

IR-1 – Attachment 1

Distribution Asset Management Program

Release Date: **March 26, 2021**

Prepared By: **T&D Operations**
T&D Engineering

MARITIME ELECTRIC
A FORTIS COMPANY

Table of Contents

1.0 INTRODUCTION

1.1 Maritime Electric Company, Limited

Maritime Electric Company, Limited ("Maritime Electric" or the "Company") has delivered electricity on Prince Edward Island ("PEI") since 1918. Maritime Electric's mandate is to provide a reliable service at the lowest possible cost, while maintaining a high level of customer service. Maritime Electric and its personnel are committed to providing this service in a safe and environmentally responsible manner.

Maritime Electric is an indirect, wholly-owned subsidiary of Fortis Inc. and operates under the provisions of Prince Edward Island's *Electric Power Act* and *Renewable Energy Act*. Maritime Electric owns and operates a fully integrated system providing for the purchase, generation, transmission, distribution and sale of electricity throughout Prince Edward Island. The Company's head office is located in Charlottetown with generating facilities in Charlottetown and Borden-Carleton. The Company has contractual entitlement to capacity and energy from New Brunswick Power ("NB Power") 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 Prince Edward Island. Through various contracts with the PEI Energy Corporation, the Company purchases the capacity and energy from 92.5 megawatts ("MW") of wind generation on PEI.

Maritime Electric's three on-Island generating stations are primarily backup supply sources. Those stations are:

- Charlottetown Thermal Generating Station ("CTGS" or "Steam Plant") - Two Generators - 40 MW
- Borden Generating Station ("BGS") - Two Generators - 40 MW
- Charlottetown Combustion Turbine No. 3 ("CT3") - One Generator - 50 MW

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 energy costs and the ability to provide backup for the four submarine cables connecting PEI to the mainland.

The CTGS is at the end of its useful life and there are numerous risks and costs associated with keeping the CTGS generating units operational. Maritime Electric has prepared a plan to decommission the CTGS in a staged approach starting with the older and smaller units. In accordance with the Decommissioning Plan, which was filed with the Island Regulatory and Appeals Commission ("IRAC" or the Commission") on June 28, 2018, the two largest units (Unit 9 and Unit 10) were placed into warm, long-term layup starting on March 1, 2019. These units are available to generate as required until December 31, 2021 on 90 days notice from NB Power as set out in the Energy Purchase Agreement ("EPA"). Unit 8 is now retired and has ceased providing capacity value or generating capability effective January 1, 2021.

Electricity on PEI is transmitted at 138 kilovolts ("kV") or 69 kV and travels along a network of high voltage transmission lines to substations situated across PEI. These substations reduce electricity voltage so that it can travel on smaller power lines, carrying electricity to transformers (on poles or on the ground) where the voltage is reduced again to deliver electrical power safely and efficiently to customers. There are over 6,000 kilometres ("km") of power lines on PEI with approximately 5,300 km for distribution and 720 km for transmission.

1.2 Objective

The objective of the Distribution Asset Management Program ("DAMP") is to prudently and effectively manage the planning, engineering, design, addition, inspection, maintenance, replacement, and retirement of distribution assets in a sustainable manner that maximizes safety and customer reliability, while minimizing costs, in the short and long terms.

This objective is achieved by thorough and sound planning, prudent and justified budgeting, documentation, and review of all efforts and expenditures while implementing the documented capital and operating work plans.

Maritime Electric will maintain a comprehensive DAMP which outlines the capital and operating processes, activities, and expenditures that are necessary to ensure that the Company continues to provide safe, reliable and efficient distribution of electricity to its customers.

There are three key principles that are integral to the DAMP:

a. Provide for the growth needs of the customers;
b. Provide safe, reliable, and high quality service; and
c. Satisfy the first two principles in a sustainable manner which minimizes the long term costs to be borne by the customers of Maritime Electric.

These key principles are derived from safety considerations; acts, regulations, codes and guidelines; good utility practice; and customer expectations. These are reviewed annually and adjustments are made to the DAMP based on changes in legislation, system performance, safety assessments, and customer feedback.

1.3 Scope

This document is intended to provide a summary of the DAMP at Maritime Electric. This document does not attempt to encompass all of the information and activities that fully define the management of distribution assets; however, it will provide a summary with sufficient detail to provide an understanding of the Company's asset management practices.

2.0 OVERVIEW

2.1 Distribution Substation Overview

The following overview describes the equipment installed in each substation and the loading of the transformers during summer peak and winter peak. A Single-Line Diagram for each substation and pictorial description of the area each substation feeds are also included. Distribution feeder voltages are typically to be 12.5 kV unless otherwise specified.

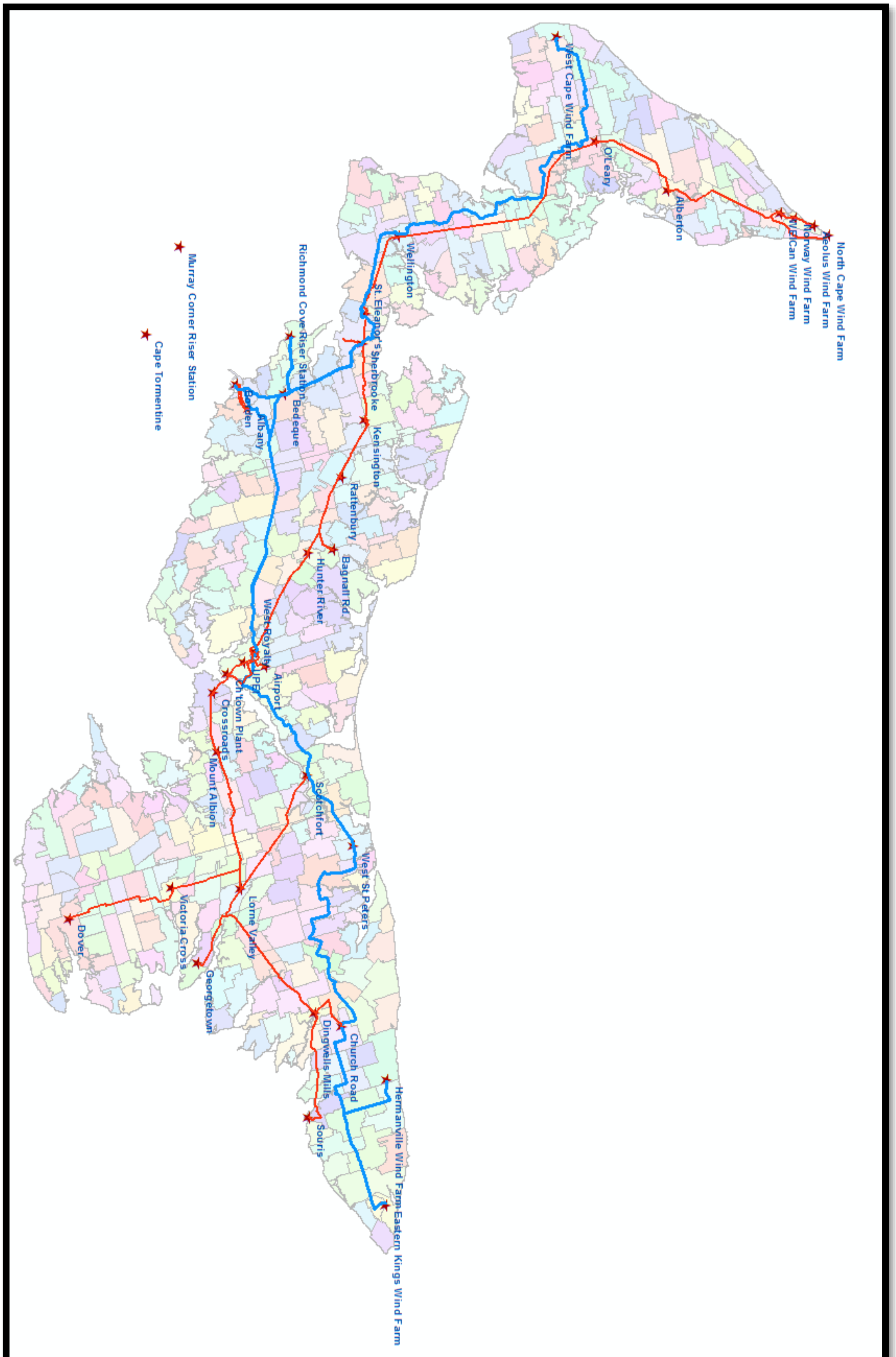

West Cape Wind Farm
O'Leary
Alberton
North Cape Wind Farm
Aeolus Wind Farm
Norway Wind Farm
WEICan Wind Farm
Wellington
St. Eleanor's
Sherbrooke
Richmond Cove Riser Station
Murray Corner Riser Station
Cape Tormentine
Borden
Albany
Bedeque
Kensington
Rattenbury
Bagnall Rd
Hunter River
West Royalty
Airport
Ch'town Plant
Crossroads
Mount Albion
Scotchfort
West St Peters
Lorne Valley
Victoria Cross
Dover
Georgetown
Dingwells Mills
Church Road
Souris
Hermanville Wind Farm
Eastern Kings Wind Farm

Figure 1: Transmission System of Prince Edward Island

2.1a Airport Distribution System

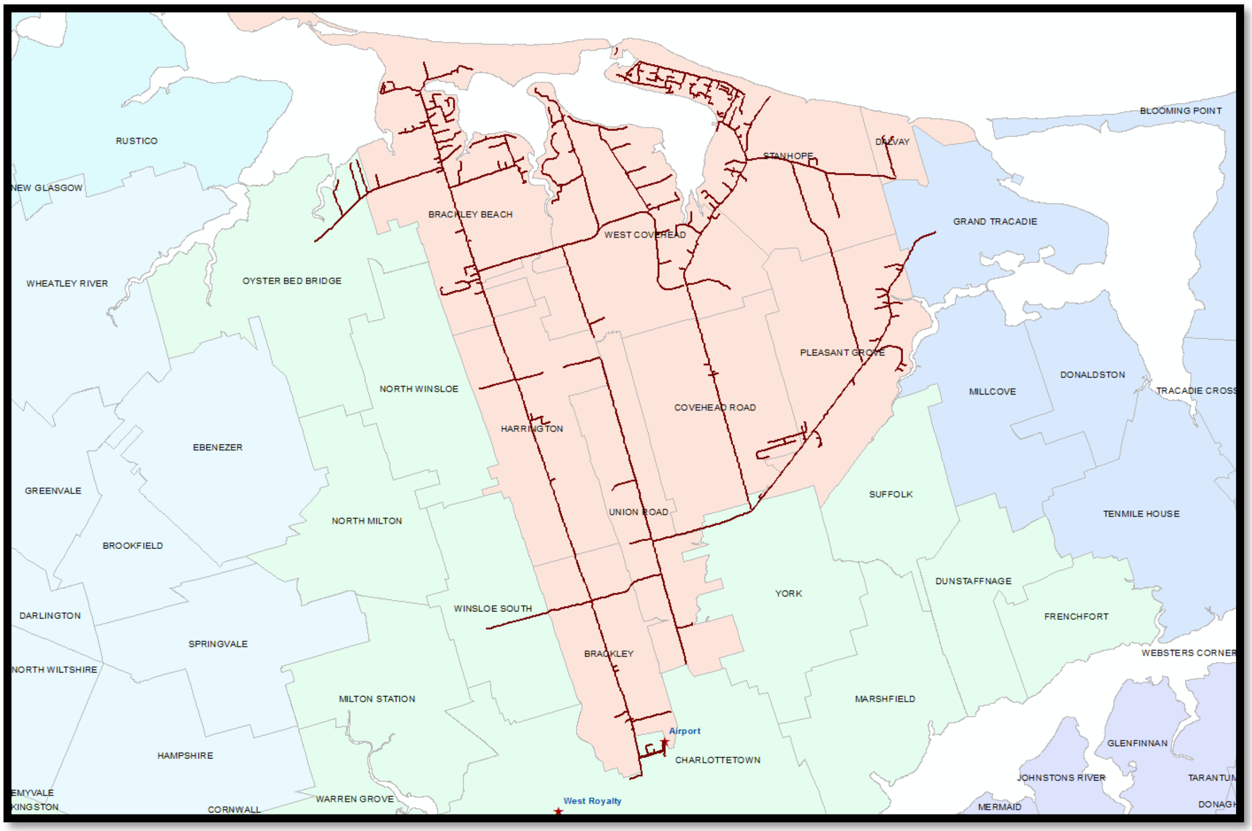


Figure 2: Service Area of Airport Substation

The Airport Substation ("AP") is located at 48 Aviation Avenue in Charlottetown. The substation is fed from 69 kV transmission line T-15 out of the West Royalty and Charlottetown Plant Substations. The substation has three circuits, Aviation Park, Covehead and Brackley. The distribution voltage at Airport Substation is 25 kV. There is one substation transformer (15/20 Megavolt Amperes ["MVA"], Company ("Co.") # 82, 2019 vintage, 69 kV – 25 kV). The substation has an on load tap changer for voltage regulation and uses bus potential transformers ("PT's") and transformer current transformers ("CT's") for metering. The substation is equipped with a mobile transformer bay, and can accept mobile transformer Co.# 79. The summer and winter peak load is 6.79 MVA and 8.05 MVA respectively. The winter peak load represents 54 per cent of the Oil Natural Air Natural ("ONAN") rating and 40 per cent of the Oil Natural Air Forced

("ONAF") rating. If needed, and depending on load condition, this substation can be paralleled with West Royalty in order to reduce the impact of a potential outage.

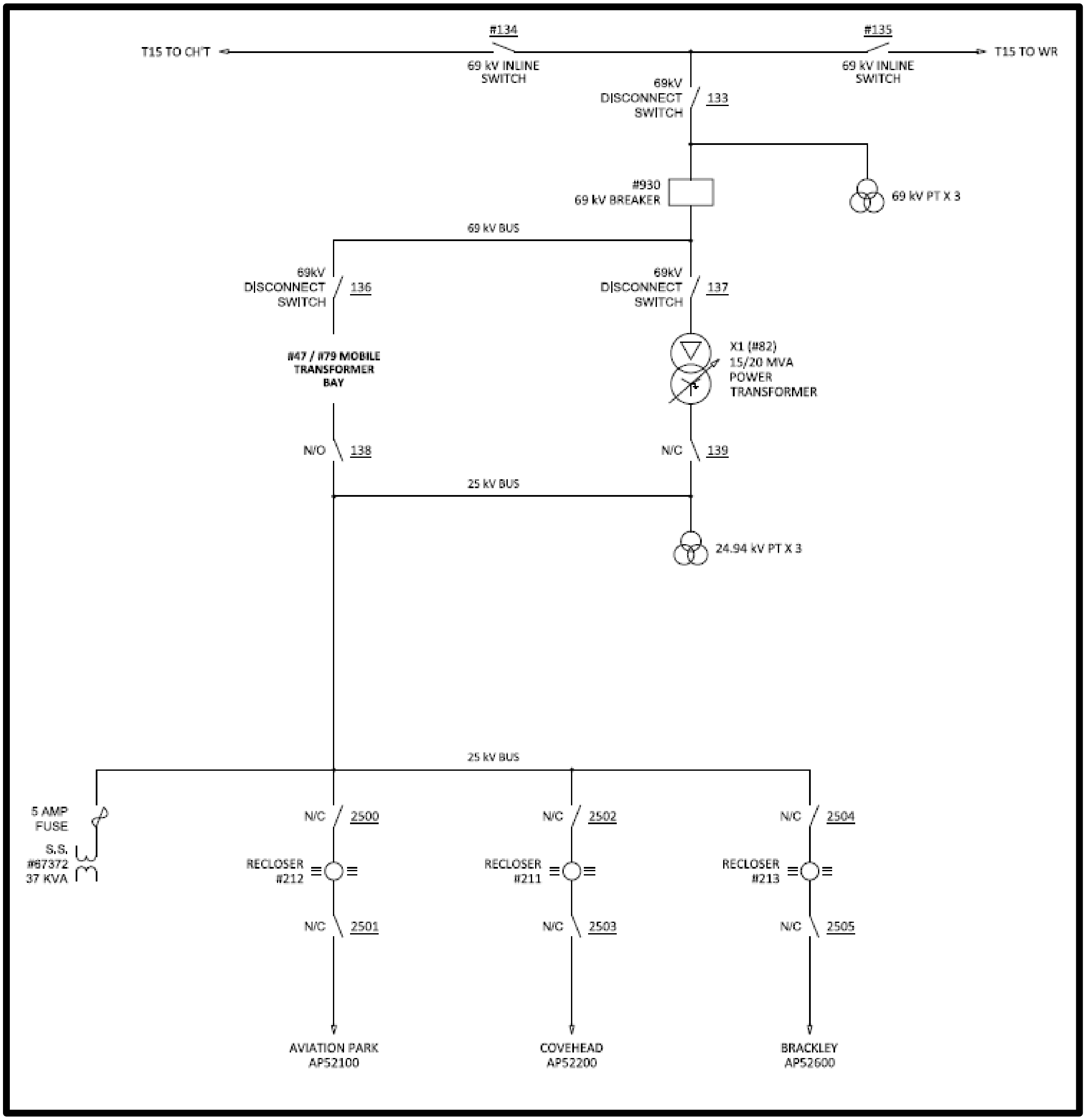


Figure 3: Single-Line Diagram of Airport Substation

2.1b **Albany Distribution System**

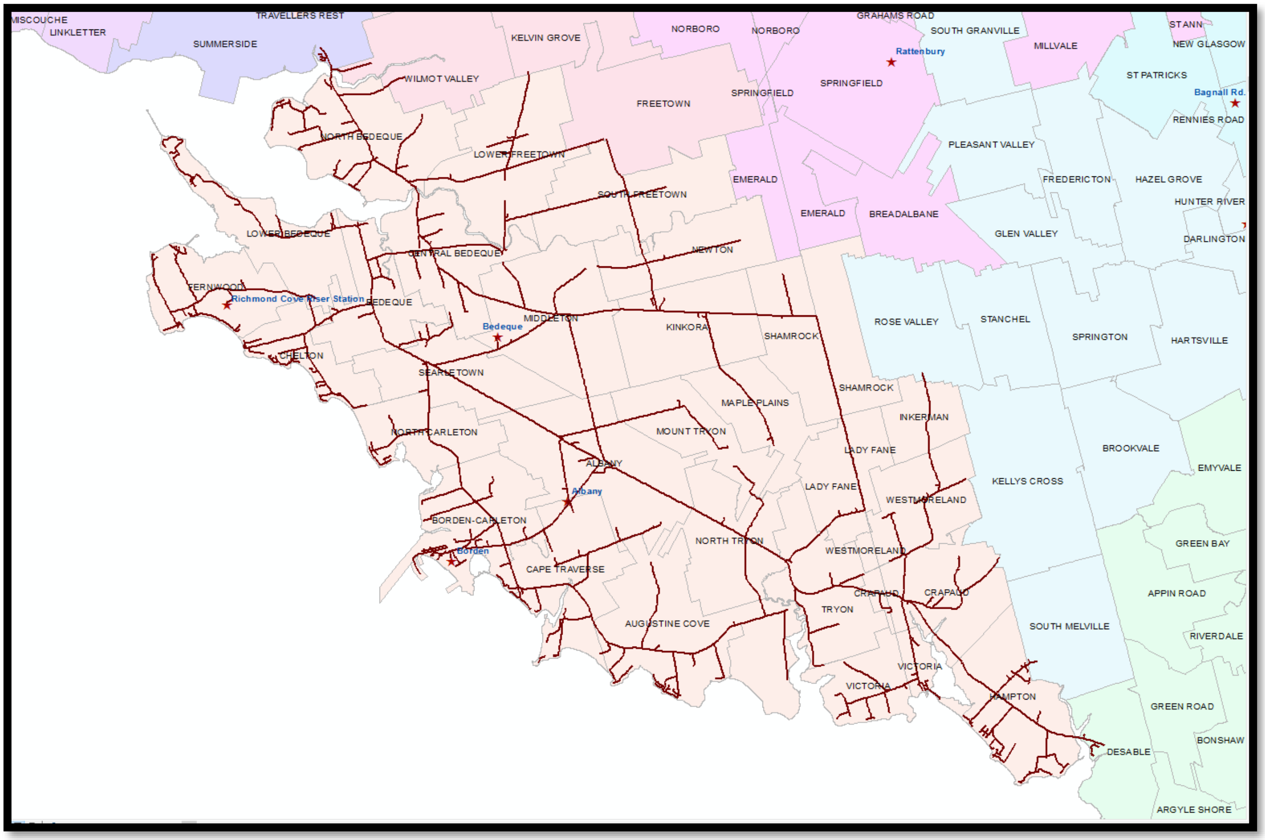


Figure 4: Service Area of Albany Substation

The Albany Substation ("AB") is located at 5 Train Station Road in Albany. The substation is fed from 69 kV transmission line T-3 out of the Borden Substation. The substation has four circuits, Augustine Cove, Crapaud, Borden Industrial Park and Bedeque. There are two substation transformers (7.5/10 MVA each: [Co.# 43, 2007 vintage, 69 kV – 12.5 kV] and [Co.# 82, 2019 vintage, 69 kV – 25 kV/12.5 kV]) that are paralleled. The substation has two sets of voltage regulators (rated 437 Amperes ["A"]) and two metering tanks. The substation is equipped with a mobile transformer bay, and can accept mobile transformer Co.# 47. The summer and winter peak load is 11.22 MVA and 14.14 MVA respectively. The winter peak load represents 94 per cent of the combined ONAN rating and 71 per cent of the combined ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Kensington in order to reduce the impact of a potential outage.

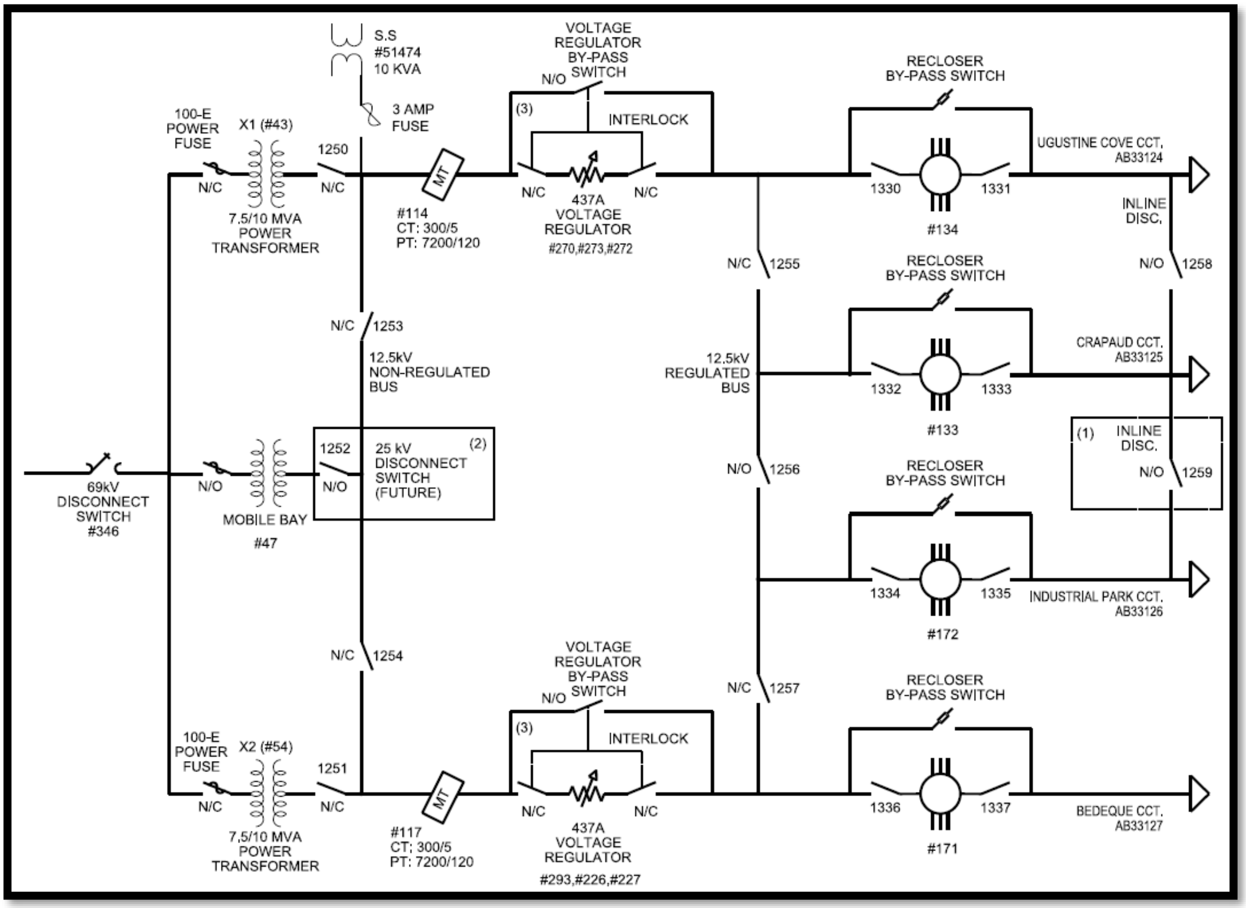


Figure 5: Single-Line Diagram of Albany Substation

2.1c Alberton Distribution System

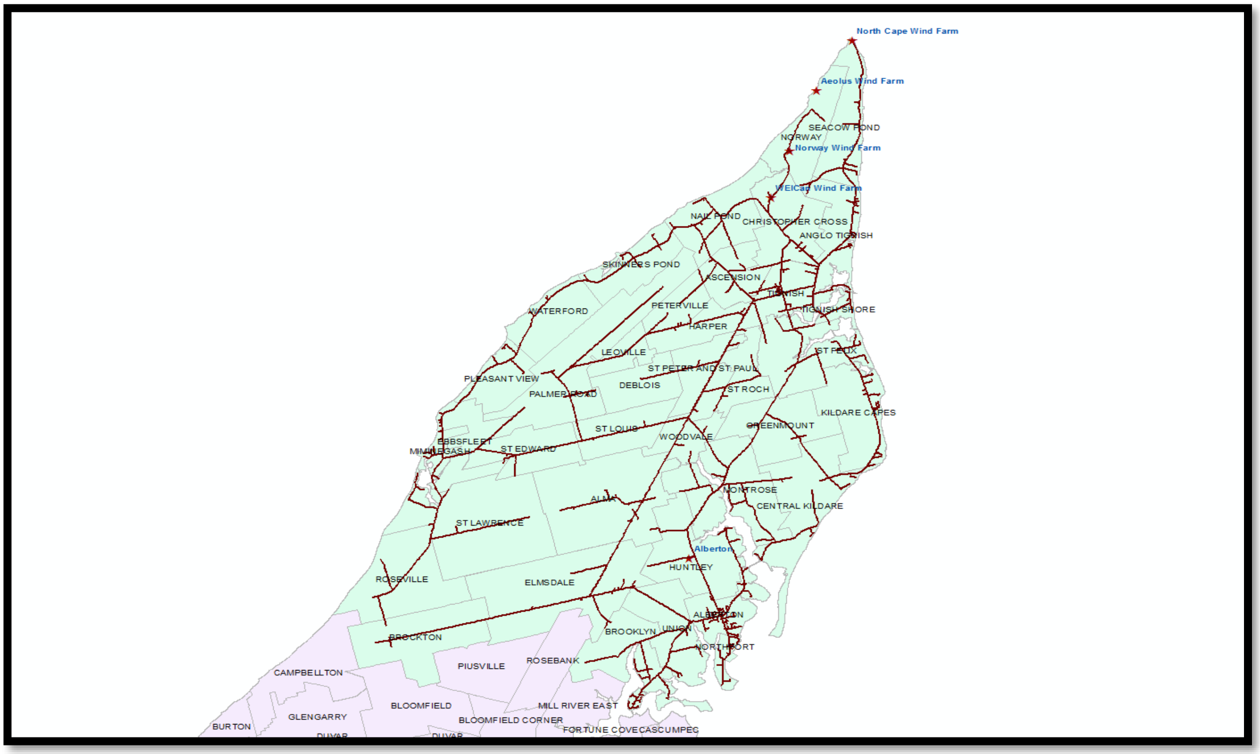


Figure 6: Service Area of Alberton Substation

The Alberton Substation ("AL") is located at 53 Oliver Road in Huntley. The substation is fed from 69 kV transmission line T-21 out of the Wellington Substation. The substation has two circuits, Tignish and Town of Alberton. There are two substation transformers ([Tignish - 7.5/10 MVA, Co.# 46, 1979 vintage, 69 kV – 12.5 kV] and [Alberton - 4/5.3 MVA, Co.# 32, 1972 vintage, 69 kV – 25 kV/12.5 kV]) that are not paralleled. The substation has two sets of voltage regulators (rated 219 A and 437 A) and two metering tanks. The substation is equipped with a mobile transformer bay, and can accept mobile transformer Co.# 47. On the Tignish transformer, the summer and winter peak load is 6.56 MVA and 7.94 MVA respectively, with the winter peak representing 106 per cent of it is ONAN rating and 79 per cent of its ONAF rating. On the Alberton transformer, the summer and winter peak load is 2.98 MVA and 4.28 MVA respectively, representing 107 per cent of it is ONAN rating and 80 per cent of its ONAF rating.

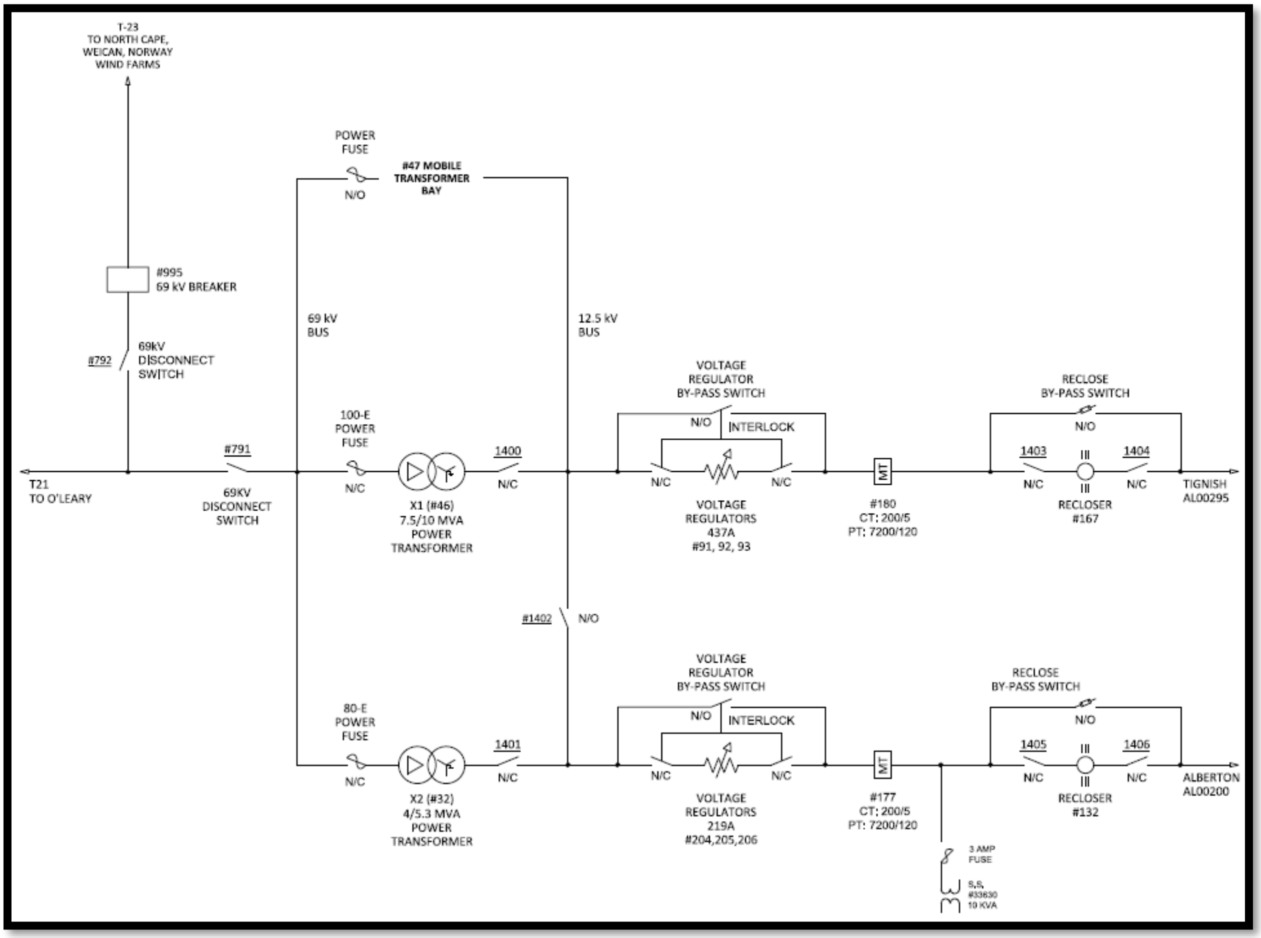


Figure 7: Single-Line Diagram of Alberton Substation

2.1d Bagnall Road Distribution System

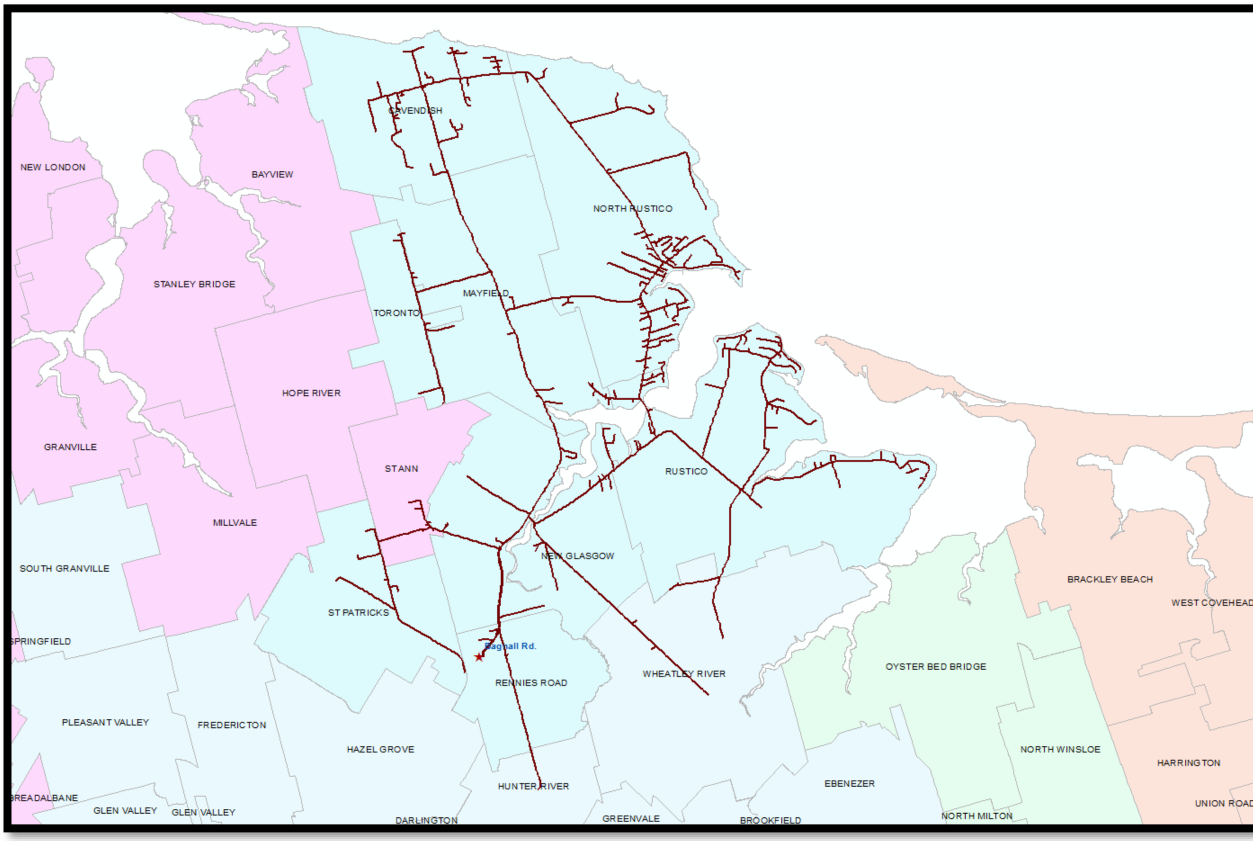


Figure 8: Service Area of Bagnall Road Substation

The Bagnall Road Substation ("BG") is located at 23 Bagnall Road in Rennies Road. The substation is fed from 69 kV transmission line T-1 out of the West Royalty Substation or the Sherbrooke Switching Station[1]. The substation has three circuits, Bayview, Cymbria and Cavendish. A transfer bus is present, which allows for any recloser to be taken out of service for maintenance without causing any customer outages. There is one substation transformer (7.5/10 MVA, Co.# 78, 2016 vintage, 69 kV – 12.5 kV). The substation has an on load tap changer for voltage regulation and uses bus potential transformers/transformer current transformers for metering. The substation is equipped with mobile transformer bay, and can accept mobile transformer Co.# 79. The summer and winter peak load is 7.71 MVA and 4.99 MVA respectively. The summer peak represents 103 per cent of the ONAN

[1] Maritime Electric differentiates a switching station from a substation on the basis that transformer conversion to a distribution voltage must occur for a facility to be called a "substation".

rating and 77 per cent of the ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Hunter River and/or Rattenbury in order to reduce the impact of a potential outage.

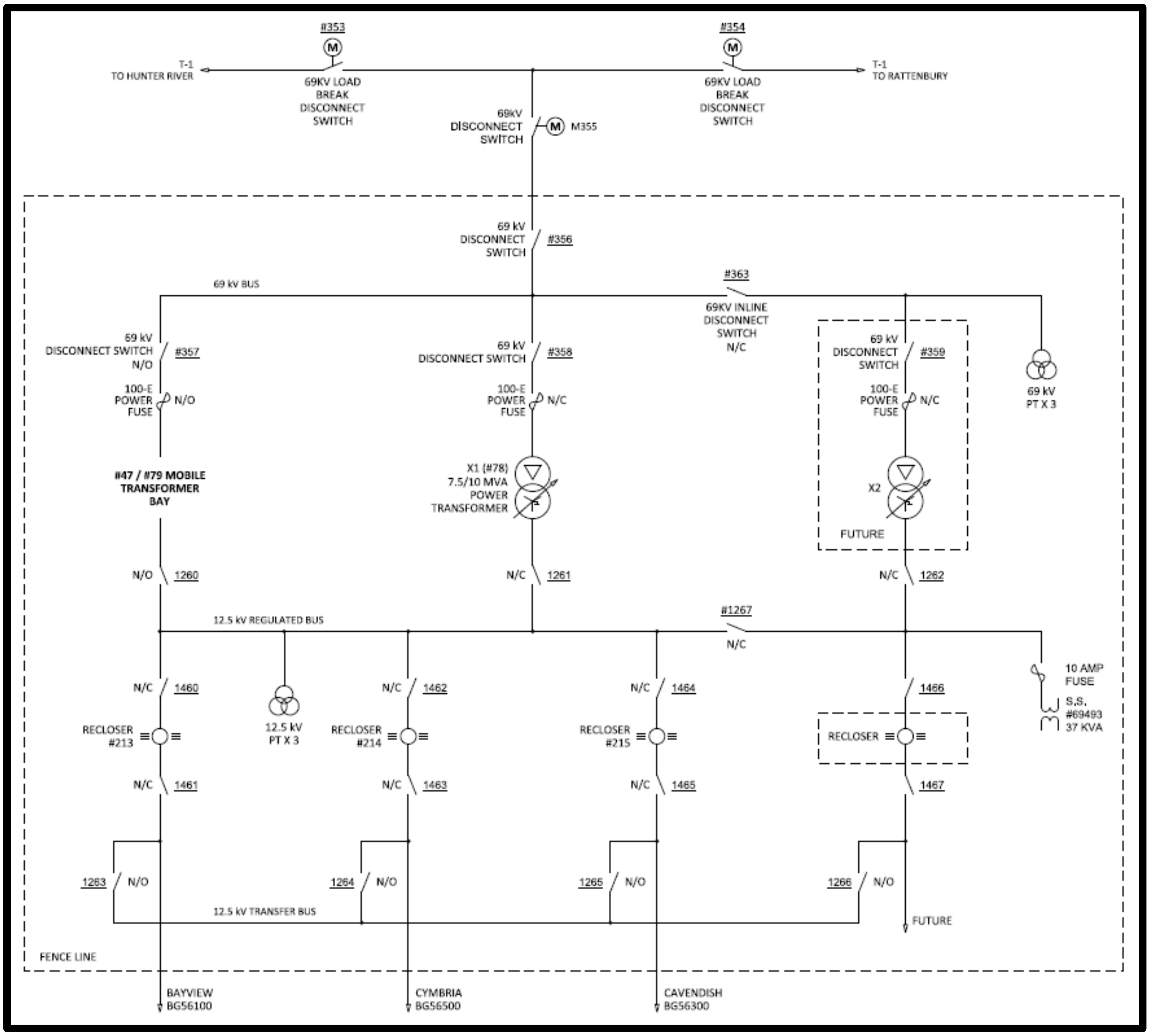


Figure 9: Single-Line Diagram of Bagnall Road Substation

2.1e Charlottetown Distribution System

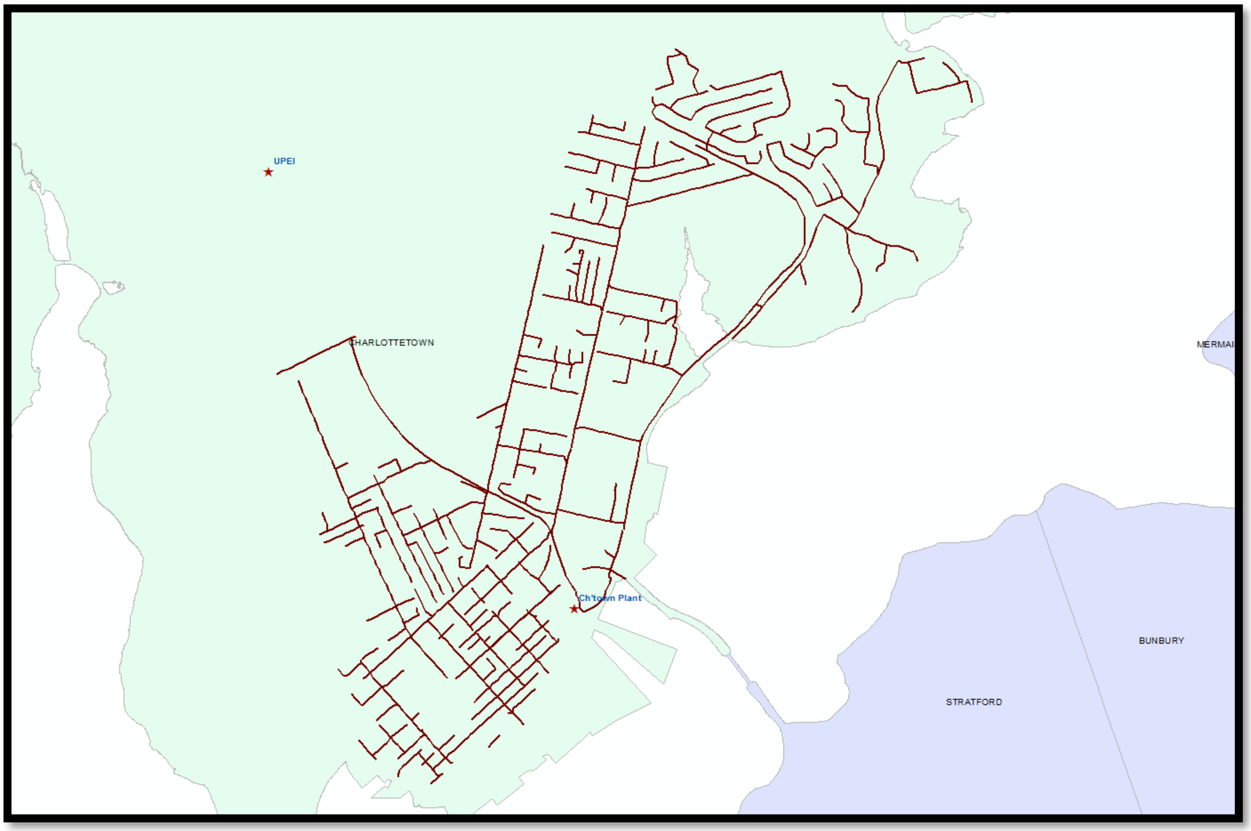


Figure 10: Service Area of Charlottetown Plant Substation

The Charlottetown Plant Substation ("CP") is located at 50 Cumberland Street in Charlottetown. The substation is fed from two 69 kV transmission lines (T-13 and T-15) out of the West Royalty Substation. The Charlottetown Plant Substation in turn feeds one 69 kV transmission line (T-2) which terminates at the Lorne Valley Switching Station.

The Charlottetown Plant Substation is unique in that it has two distribution voltages 13.8 kV and 4.16 kV and the bus work for these distribution feeders is housed within metal clad switchgear which is also used to supply station service and large motor feeds to the adjacent Charlottetown Thermal Generating Station.

One 45/60 MVA substation transformer (X4, Co.# 63, 2005 vintage, 69 kV – 13.8 kV) supplies five 13.8 kV Charlottetown area distribution circuits, Euston Street, Riverside Drive, King Street, Prince Street and Confederation. The substation has an on load tap changer for voltage regulation and the metal clad switchgear is equipped with CTs and PTs to provide individual feeder metering. The substation does not have a mobile transformer bay. If needed customers can be supplied from an adjacent substation (UPEI or West Royalty) or from CT3 directly. The summer and winter peak load for the 13.8 kV distribution is 29.9 MVA and 29.9 MVA respectively. The peak load represents 66 per cent of the ONAN rating and 50 per cent of the ONAF rating.

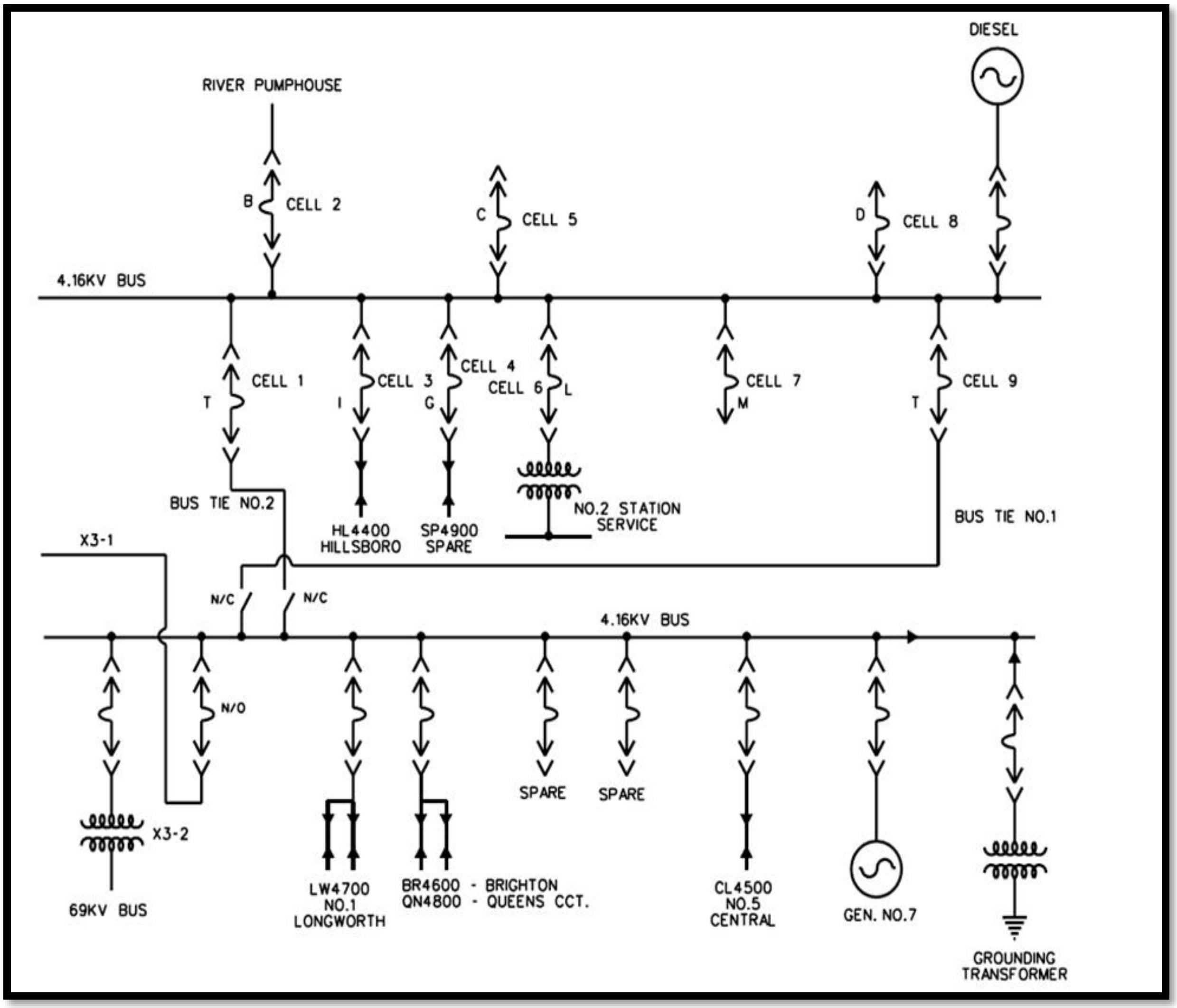


Figure 11: Single-Line Diagram of Charlottetown Plant Substation 4.16 kV Distribution System

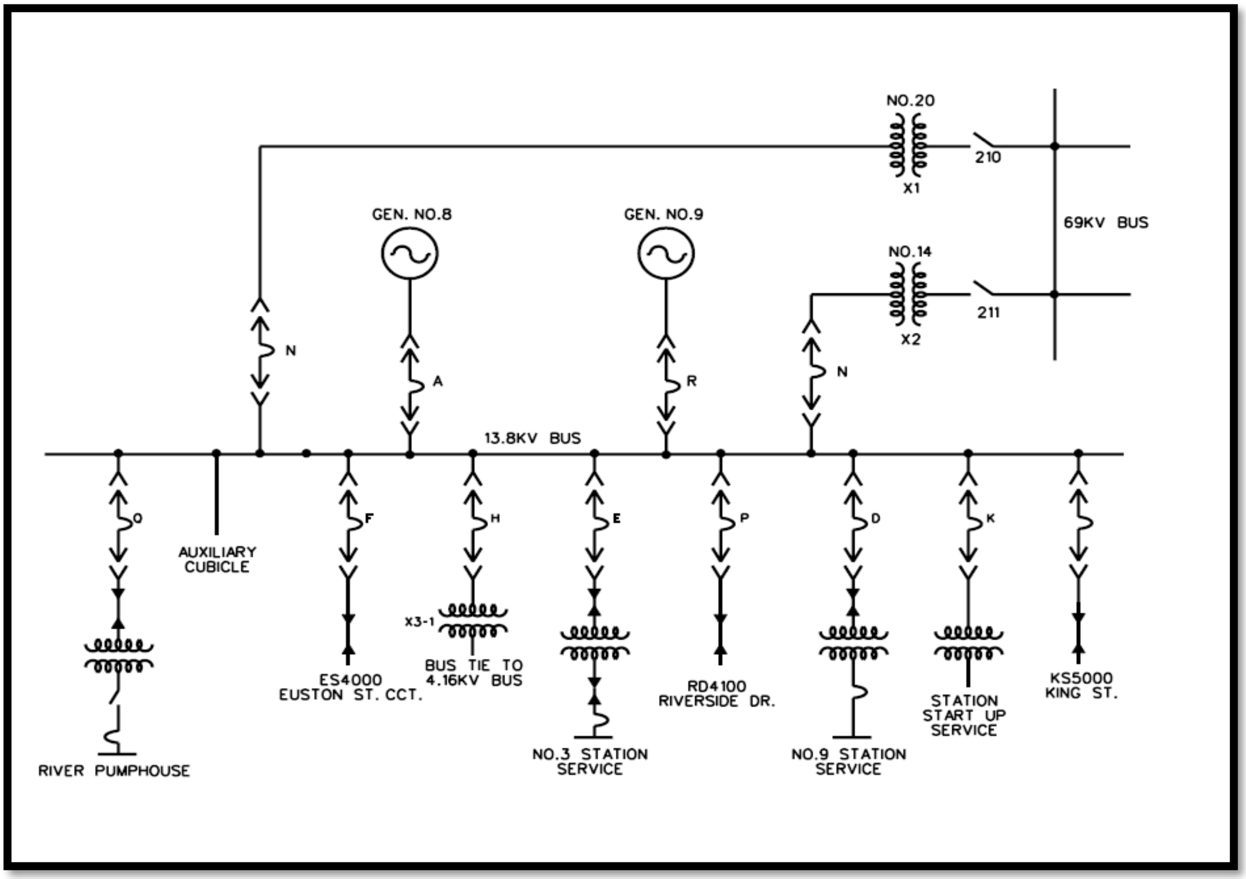


Figure 12: Single-Line Diagram of Charlottetown Plant Substation 13.8 kV Distribution System

2.1f Crossroads Distribution System

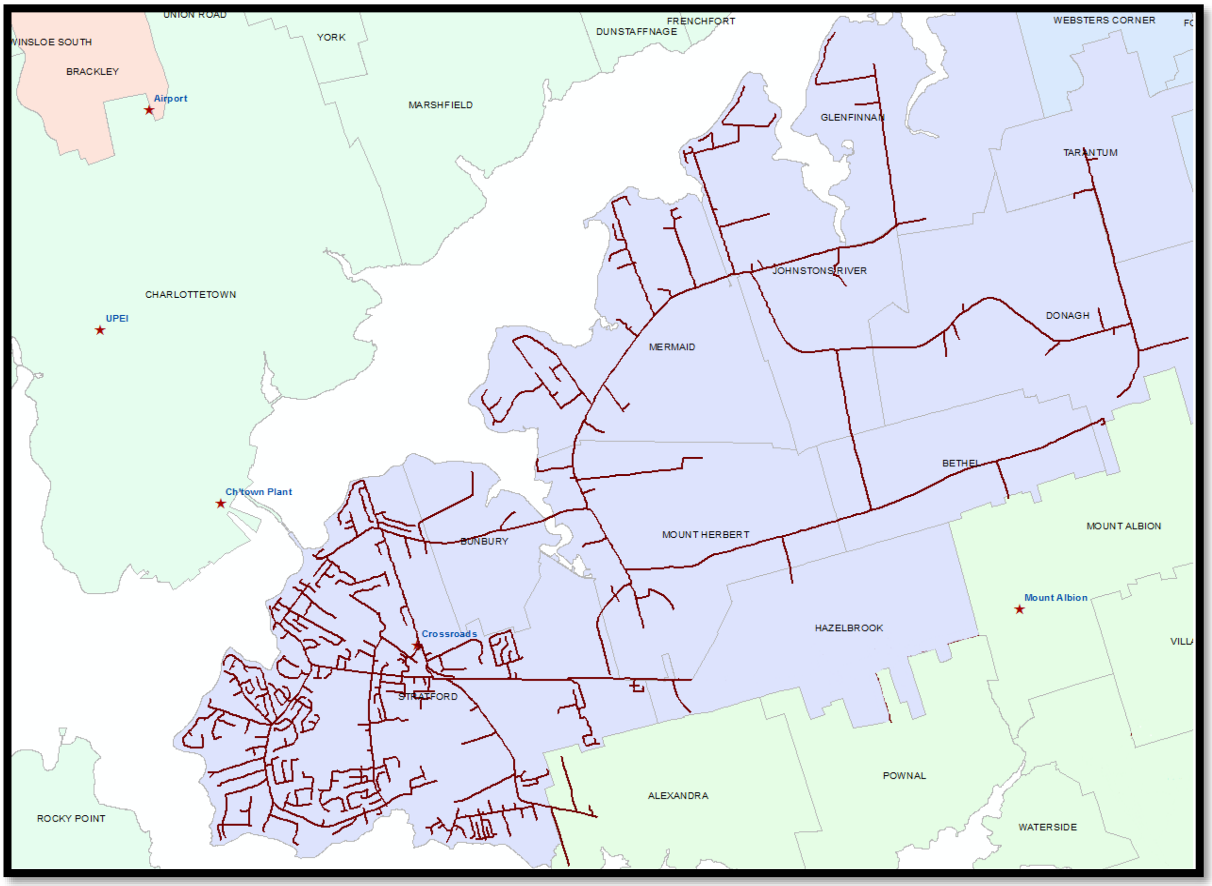


Figure 13: Service Area of Crossroads Substation

The Crossroads Substation ("CR") is located at 110 Mason Road in Stratford. The substation is fed from 69 kV transmission line T-2 out of the Charlottetown Plant Substation and the Lorne Valley Switching Station. The substation has four circuits, Kinlock, Bunbury, Tea Hill/Pownal and Southport. There are two 7.5/10 MVA substation transformers that are paralleled ([Co.# 64, 2005 vintage, 69 kV – 12.5 kV] and [Co.# 66, 2007 vintage, 69 kV – 12.5 kV]). The substation has four sets of voltage regulators (three sets are 437 A, one set is 328 A) and a metering tank. The substation is equipped with a mobile transformer bay, and can accept mobile transformer Co.# 47. The summer and winter peak load is 10.0 MVA and 17.2 MVA respectively. The winter peak represents 115 per cent of the combined ONAN rating and 86 per cent of the combined ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Mount Albion in order to reduce the impact of a potential outage.

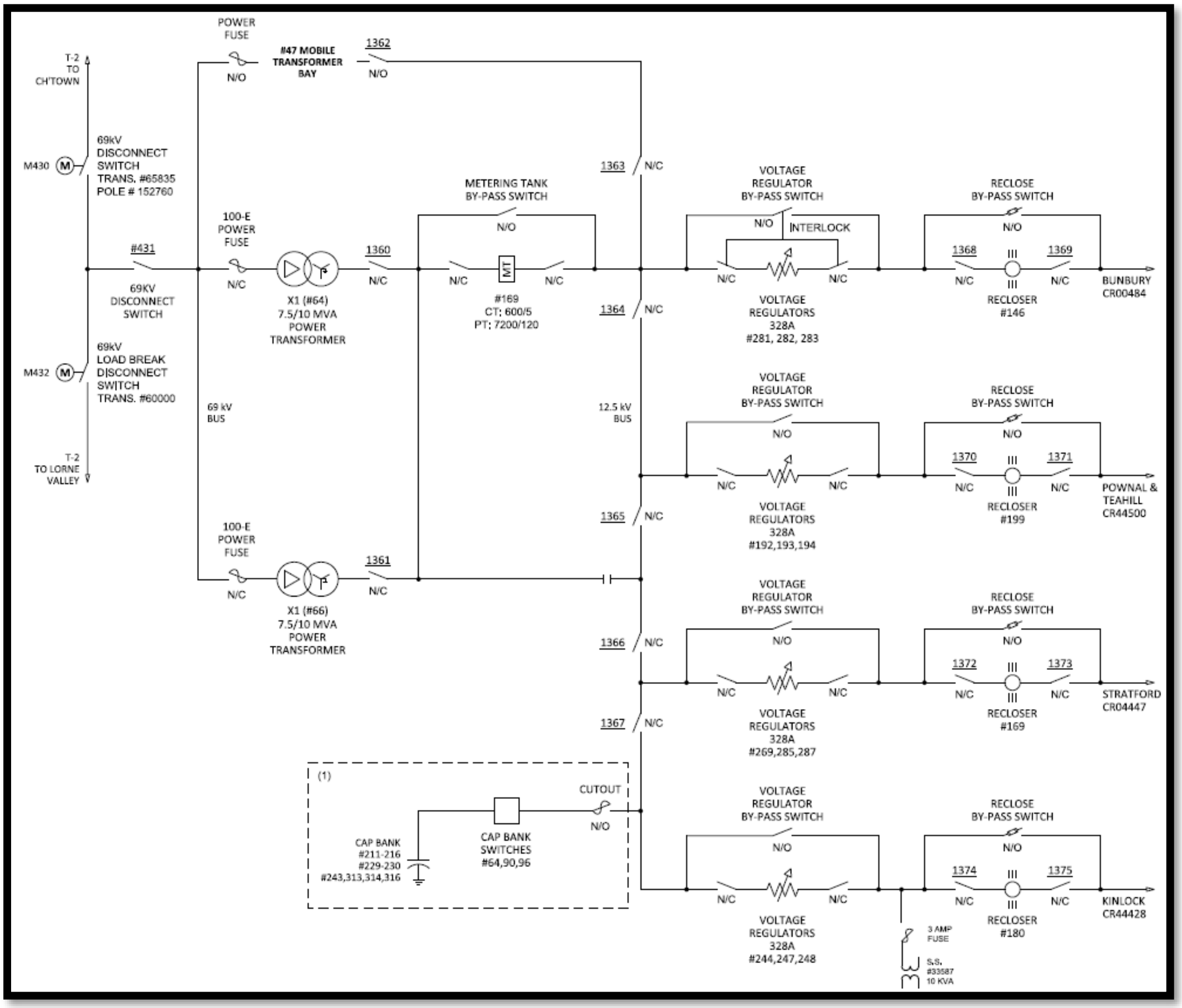


Figure 14: Single-Line Diagram of Crossroads Substation

2.1g Dingwells Mills Distribution System

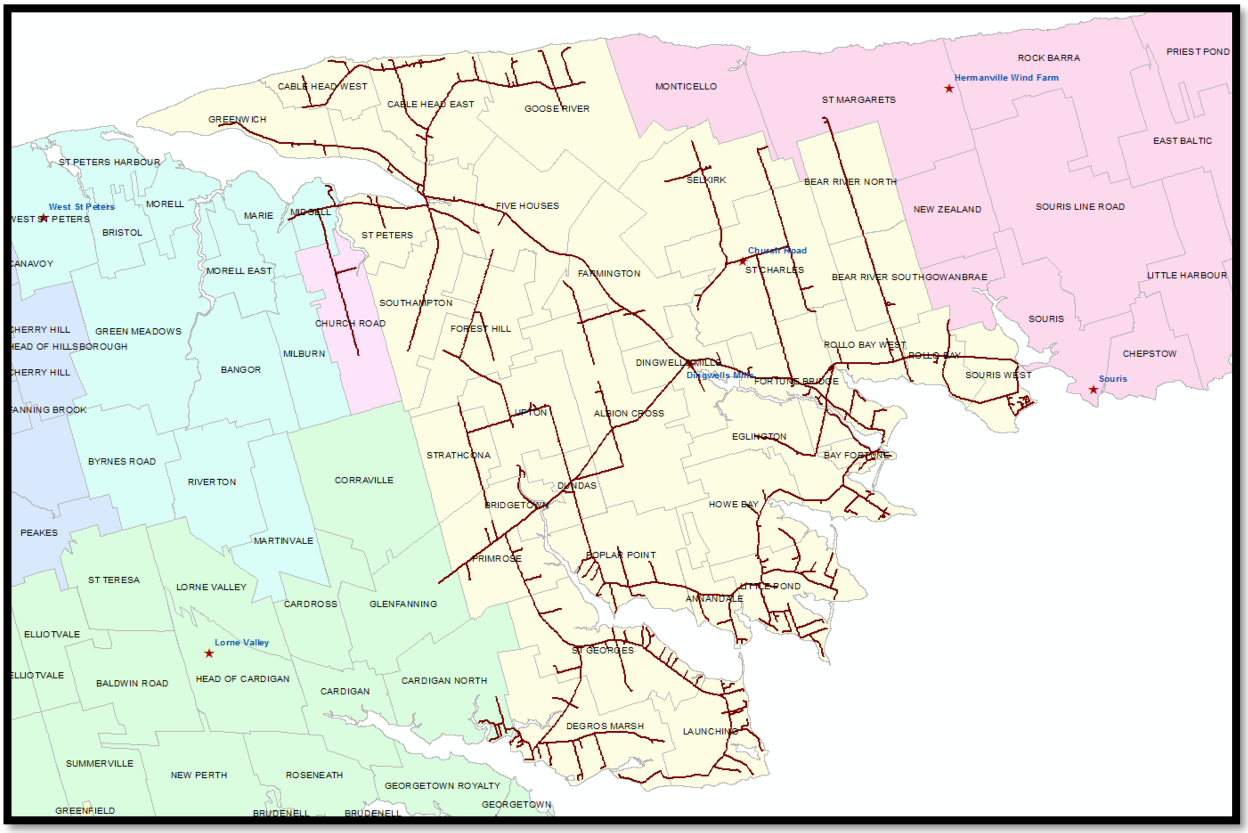


Figure 15: Service Area of Dingwells Mills Substation

The Dingwells Mills Substation ("DM") is located at 1740 Fortune Road, Route 332 in Dingwells Mills. The substation is fed from 69 kV transmission line T-8 out of the Church Road and Lorne Valley Switching Stations. The substation has three circuits, Souris, Dundas and St. Peters. The substation has one set of voltage regulators (rated 328 A) and one metering tank. The substation is equipped with a mobile transformer bay, and can accept mobile transformer Co.# 47. There is one substation transformer (rated 5/6.7 MVA, Co.# 35, 1973 vintage, 69 kV – 12.5 kV) that has a summer peak load of 3.8 MVA and winter peak load of 5.2 MVA. This represents 104 per cent of the ONAN rating and 78 per cent of the ONAF rating. If needed, and depending on load condition, this substation can be paralleled with West St. Peters in order to reduce the impact of a potential outage.

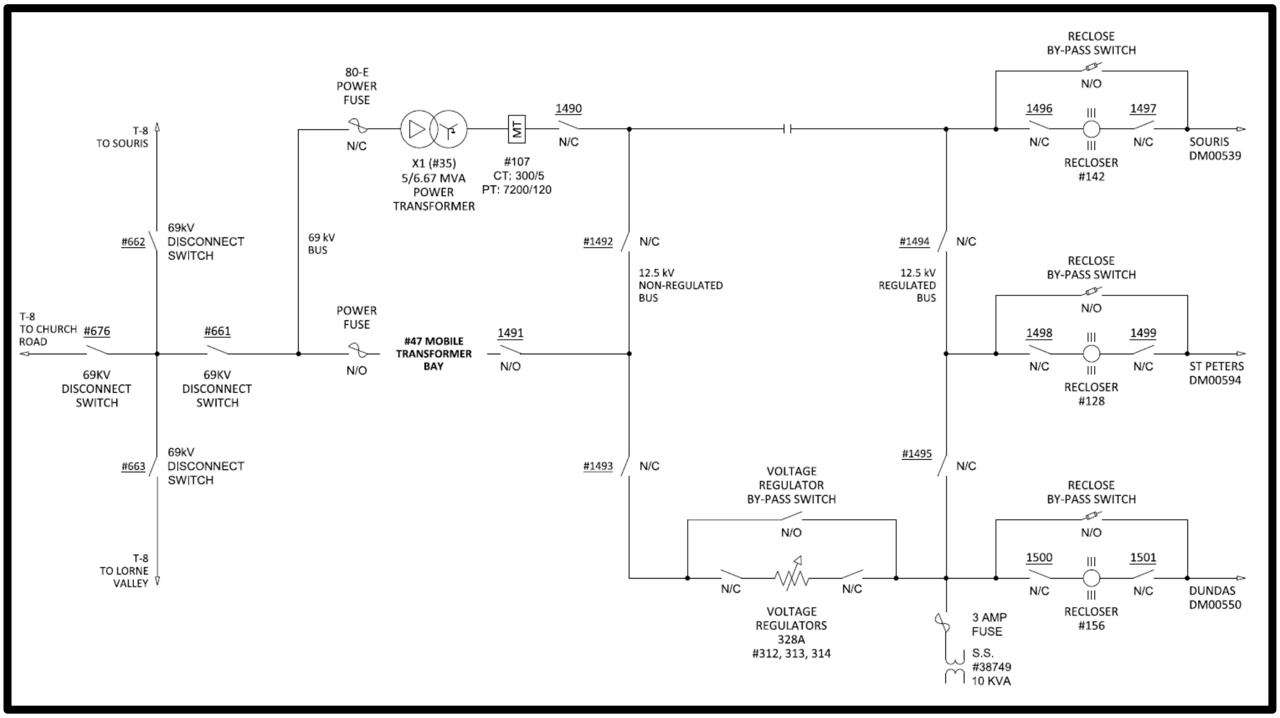


Figure 16: Single-Line Diagram of Dingwells Mills Substation

2.1h Dover Distribution System

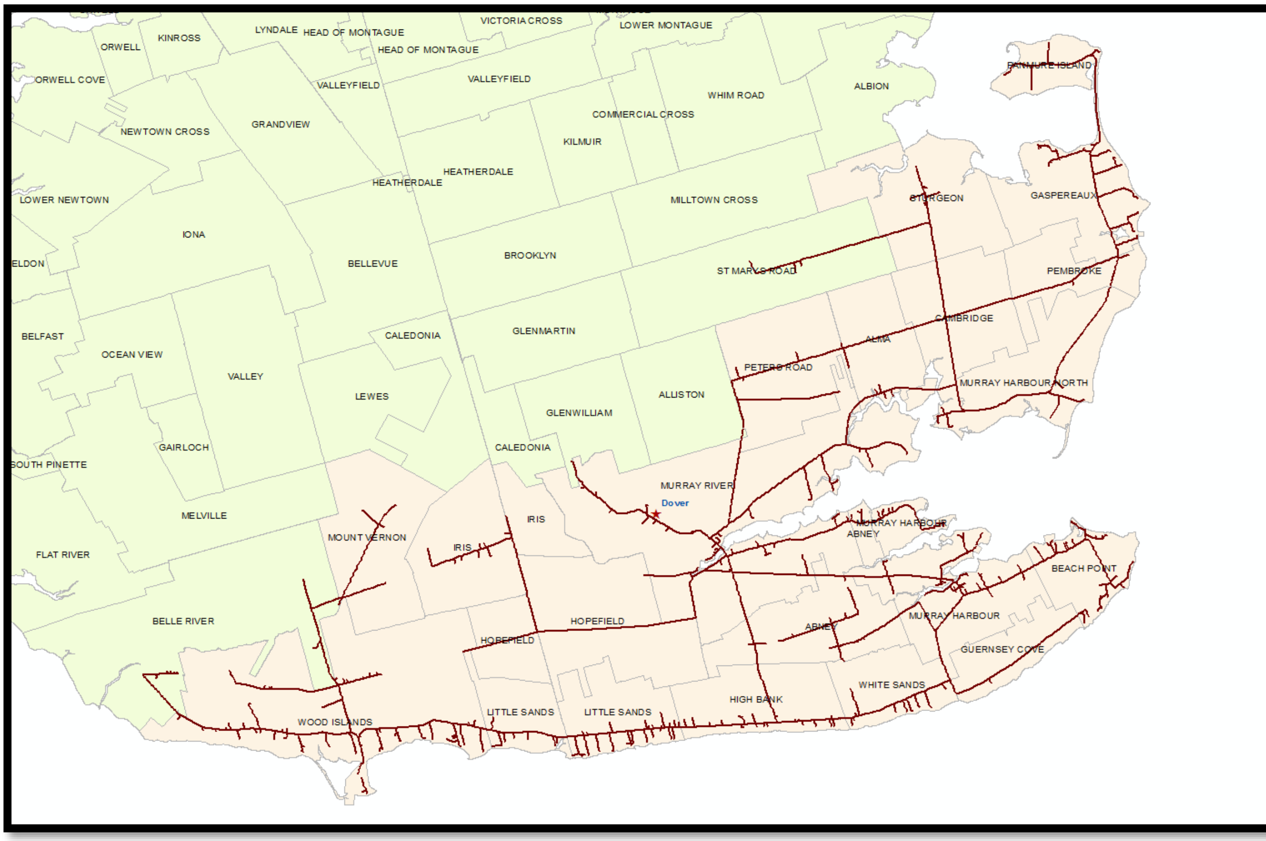


Figure 17: Service Area of Dover Substation

The Dover Substation ("DV") is located at 374 Dover Road, along Route 24 in Dover. The substation is fed from 69 kV transmission line T-10 out of the Lorne Valley Switching Station. The substation has two circuits, Wood Islands and Greek River. There is one 5/6.67 MVA (Co.# 25, 1967 vintage, 69 kV – 25 kV / 12.5 kV) substation transformer, one set of voltage regulators (rated 219 A) and a metering tank. The substation is equipped with a mobile transformer bay, and can accept mobile transformer Co.# 47. The summer and winter peak load is 3.7 MVA and 4.5 MVA respectively. The winter peak represents 90 per cent of the ONAN rating and 67 per cent of the ONAF rating.

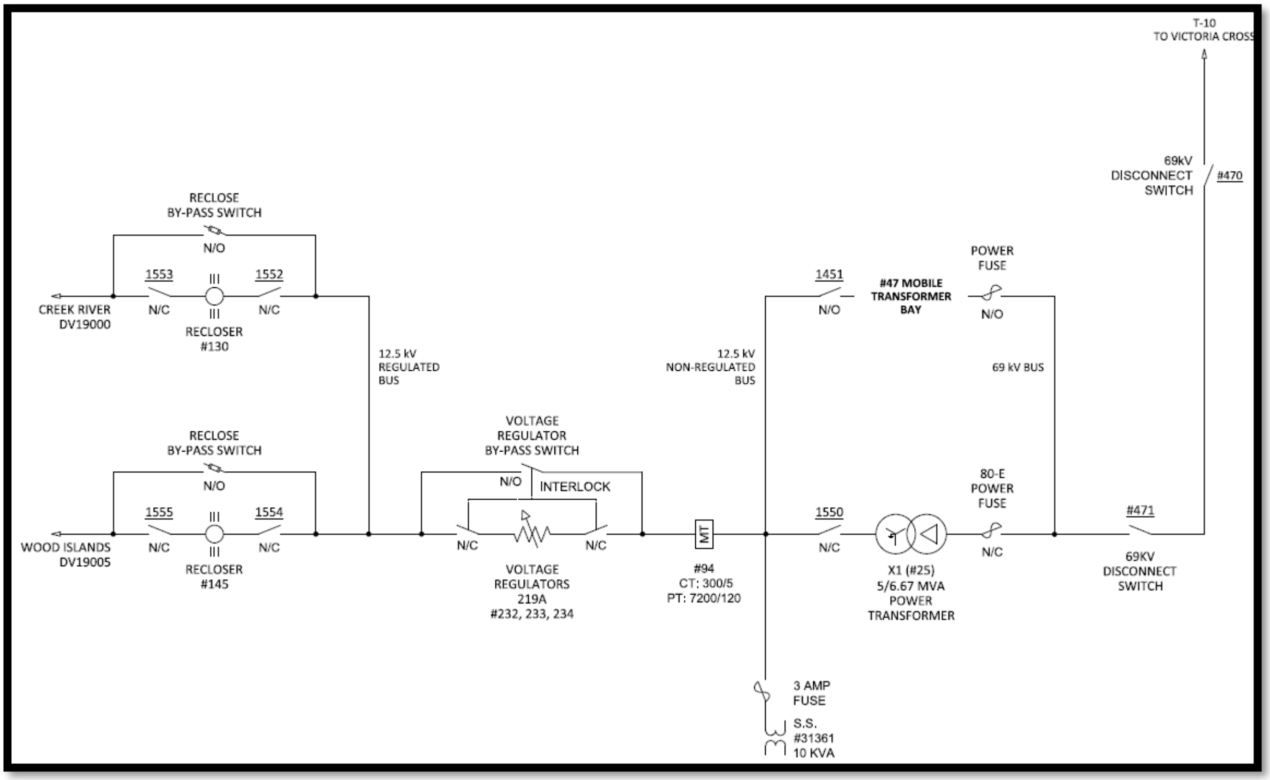


Figure 18: Single-Line Diagram of Dover Substation

2.1i Georgetown Distribution System

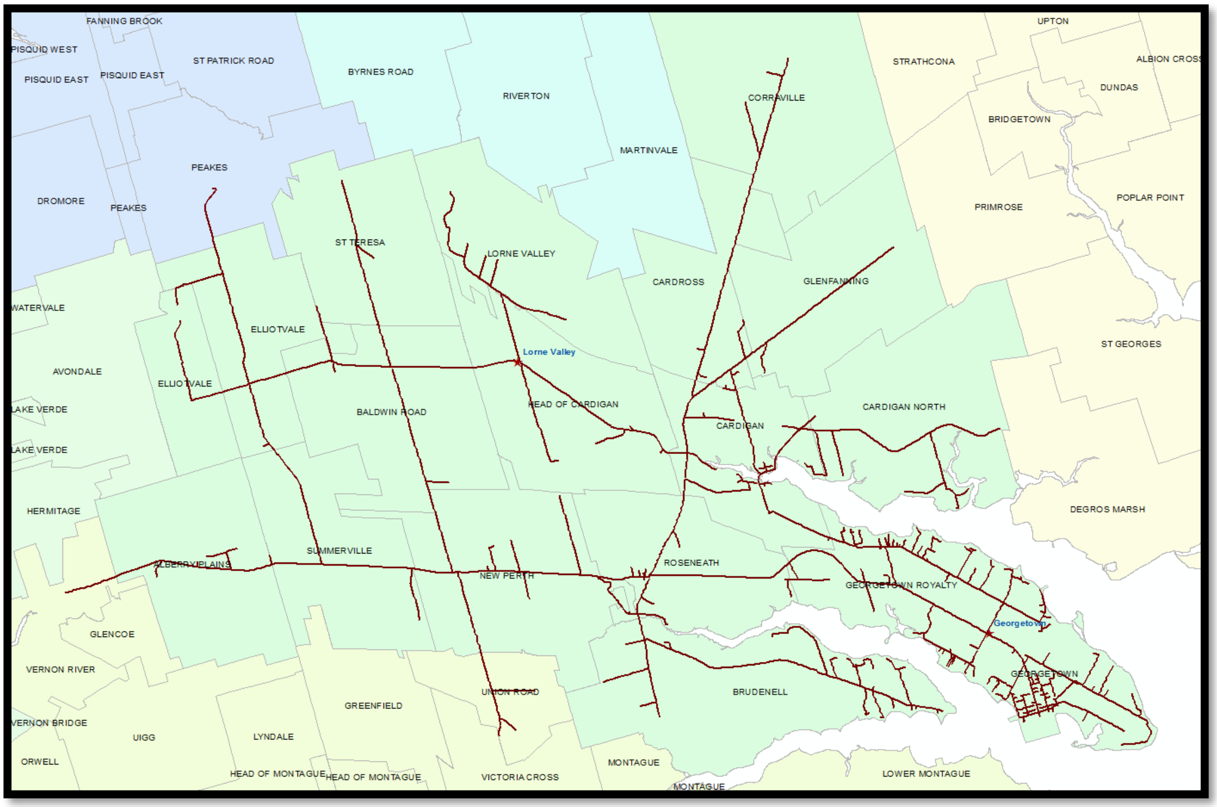


Figure 19: Service Area of Georgetown Substation

The Georgetown Substation ("GT") is located at 8 Morrisons Beach Road in Georgetown. The substation is fed from 69 kV transmission line T-8 out of the Church Road and Lorne Valley Switching Stations. The substation has two distribution circuits, Georgetown and Poole's Corner. There is one transformer (7.5/10 MVA, Co.# 60, 2000 vintage, 69 kV – 12.5 kV) in the substation. The substation has one set of voltage regulators (rated 328 A) and one metering tank. The summer and winter peak loads of 4.8 MVA and 5.7 MVA respectively are lower than historical highs due to the closure of some industrial customers in the area including a fish plant, a saw mill and a shipbuilding facility. The Georgetown Substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 47. The winter peak load represents 76 per cent of the ONAN rating and 57 per cent of the ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Mount Albion and/or Victoria Cross in order to reduce the impact of a potential outage.

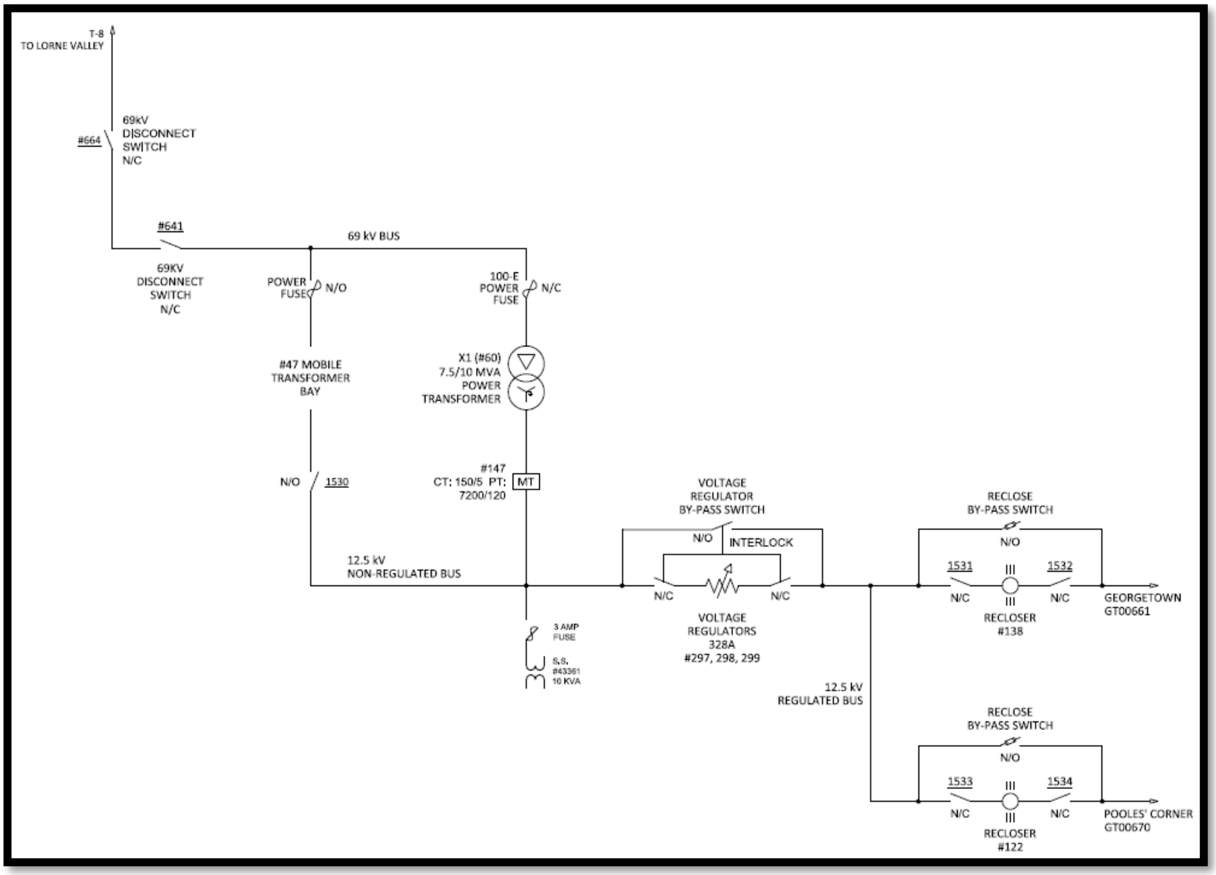


Figure 20: Single-Line Diagram of Georgetown Substation

2.1j Hunter River Distribution System

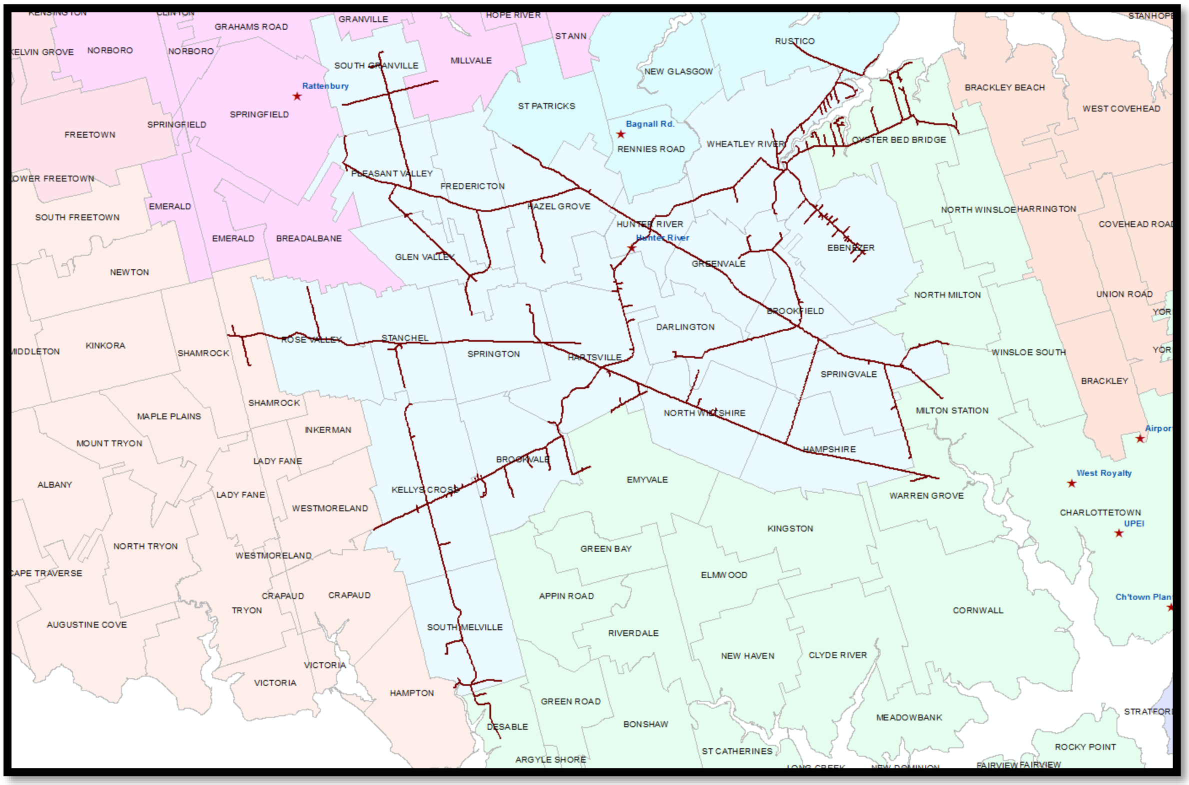


Figure 21: Service Area of Hunter River Substation

The Hunter River Substation ("HR") is located at 4090 Hopedale Road, Route 13, Hunter River. The substation is normally fed from 69 kV transmission line T-1 out of the West Royalty Substation but it can also be fed from the Sherbrooke Switching Station. The substation has two distribution circuits, Malpeque and Rennies Road. There is one substation transformer (7.5/10 MVA, Co.# 58, 1998 vintage, 69 kV – 12.5 kV), one set of voltage regulators (rated 437 A) and one metering tank. The substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 47. The summer and winter peak loads are 4.4 MVA and 6.6 MVA respectively. The winter peak load represents 88 per cent of the ONAN rating and 66 per cent of the ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Bagnall Road in order to reduce the impact of a potential outage.

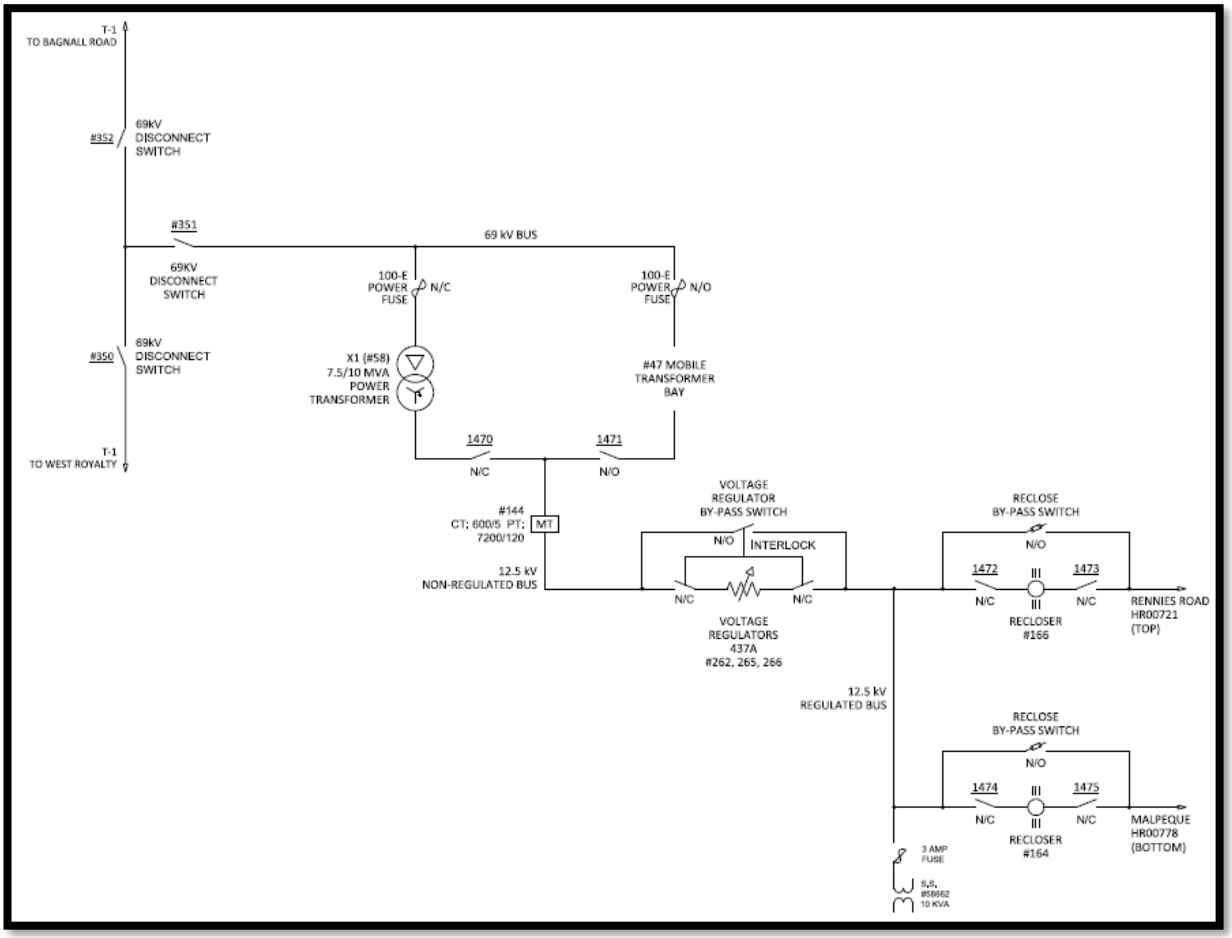


Figure 22: Single-Line Diagram of Hunter River Substation

2.1k Kensington Distribution System

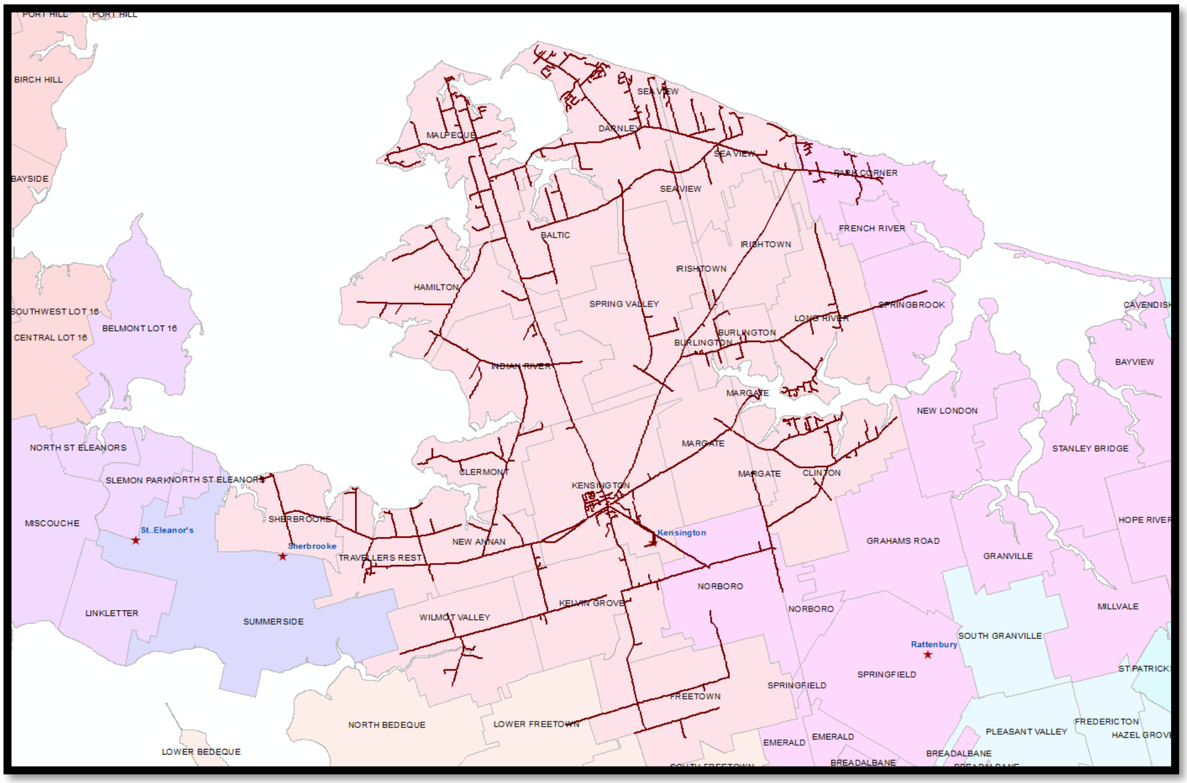


Figure 23: Service Area of Kensington Substation

The Kensington Substation ("KN") is located at 24412 Route #2, Kensington. The substation is fed from 69 kV transmission line T-1 that is normally fed out of Sherbrooke Switching Station but can also be fed out of the West Royalty Substation. The substation has three circuits, Norboro, Irishtown and New Annan. There are two substation transformers ([5/6.7 MVA, Co.# 39, 1977 vintage, 69 kV – 12.5 kV] and [7.5/10 MVA, Co.# 72, 2012 vintage, 69 kV – 12.5 kV]) which are paralleled. The substation has two sets of voltage regulators (both rated 437 A). The substation uses feeder recloser data for metering. The substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 47. The summer and winter peak load is 8.8 MVA and 12.3 MVA respectively. The winter peak is 98 per cent of the combined ONAN rating and 74 per cent of the combined ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Albany and/or Rattenbury in order to reduce the impact of a potential outage.

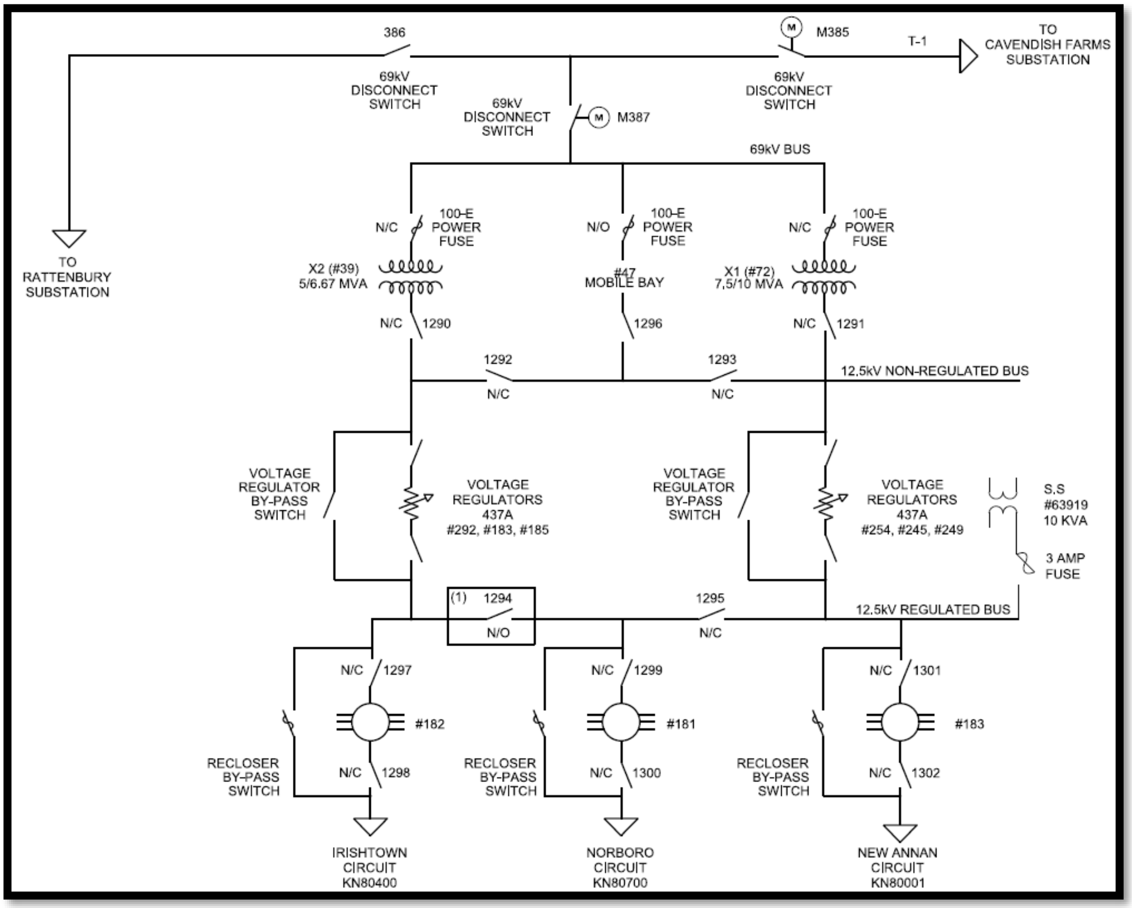


Figure 24: Single-Line Diagram of Kensington Substation

2.1l Mount Albion Distribution System

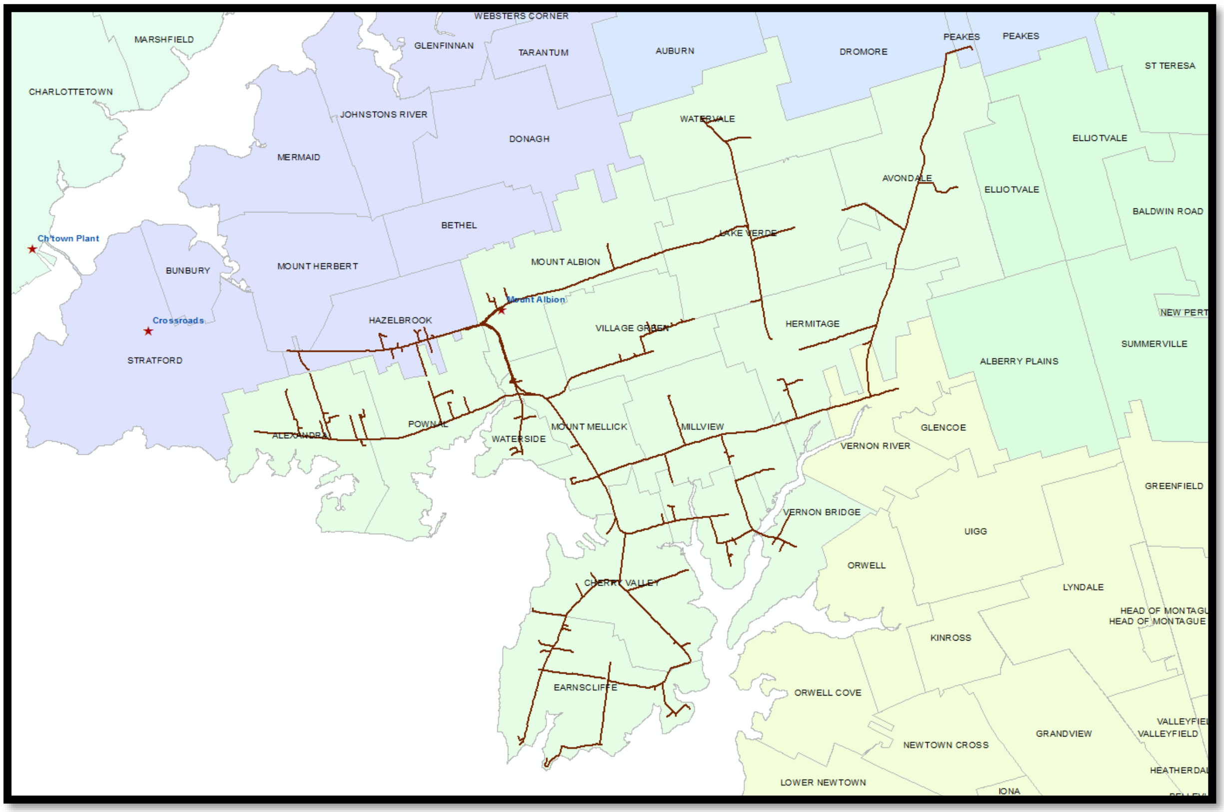


Figure 25: Service Area of Mount Albion Substation

The Mount Albion Substation ("MA") is located at 124 48 Road, Route 5, Mount Albion. The substation is fed from 69 kV transmission line T-2 fed out of the Charlottetown Plant and Lorne Valley Switching Station. The substation has three distribution circuits, Hazelbrook, Alexandra and Vernon River. A transfer bus is present, which allows for any recloser to be taken out of service for maintenance, without causing any customer outages. There is one substation transformer (7.5/10 MVA, Co.# 81, 2018 vintage, 69 kV – 12.5 kV) in the substation. The substation has an on load tap changer for voltage regulation and uses bus PT's and transformers CT's for metering. The substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 79. The summer and winter peak load is 2.5 MVA and 3.6 MVA respectively. The winter peak is 48 per cent of the ONAN rating and 36 per cent of ONAF rating. More load will be transferred from Crossroad Substation to Mount Albion Substation in the coming years. If needed, and depending on load condition, this substation can be paralleled with Crossroads and/or Georgetown in order to reduce the impact of a potential outage.

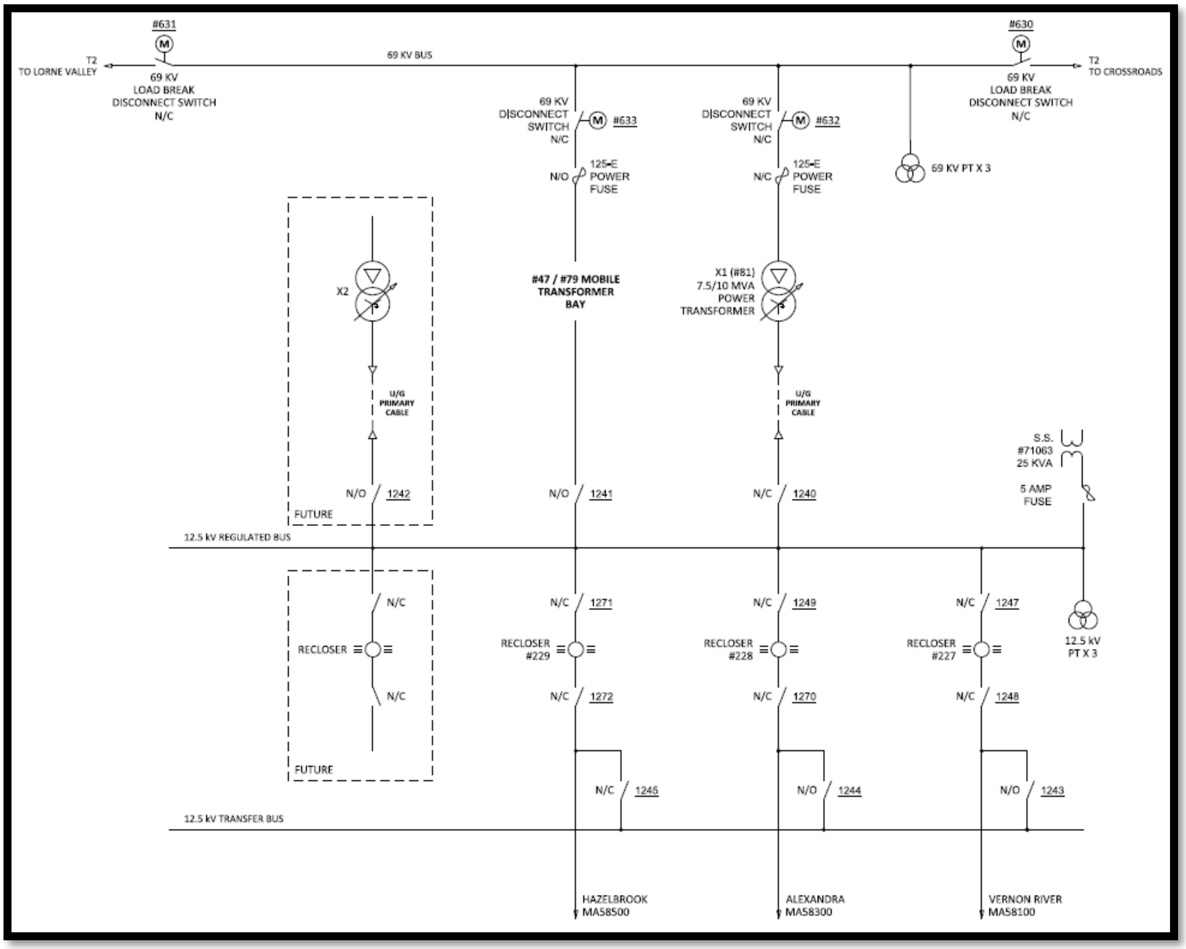


Figure 26: Single-Line Diagram of Mount Albion Substation

2.1m O'Leary Distribution System

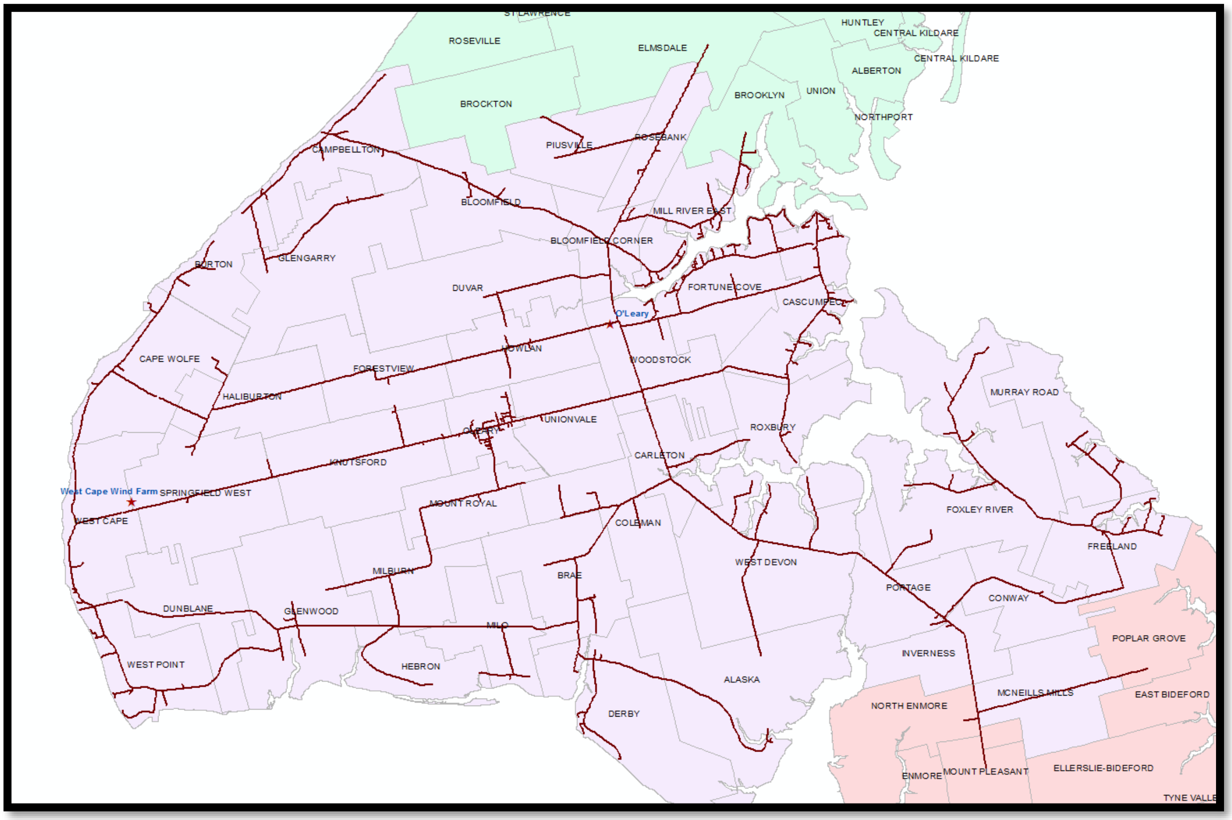


Figure 27: Service Area of O'Leary Substation

The O'Leary Substation ("OL") is located at 63 Howlan Road, Route 143, Woodstock. The substation is fed from the 69 kV transmission line T-21 out of Wellington. The substation has two distribution circuits O'Leary and Howlan Road. There are two substation transformers (7.5/10 MVA each: [Co.# 57, 1995 vintage, 69 kV – 25 kV/12.5 kV] and [Co.# 65, 2006 vintage, 69 kV – 12.5 kV]) which are paralleled. The substation has two sets of voltage regulators (each rated 437 A) and one metering tank for transformer #57. Transformer #65 is metered according to transformer CT's and the metering tank PT's. The substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 47. The summer peak load is 7.4 MVA while the winter peak load is 10.1 MVA. The winter peak represents 67 per cent of the combined ONAN rating and 51 per cent of the combined ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Wellington in order to reduce the impact of a potential outage.

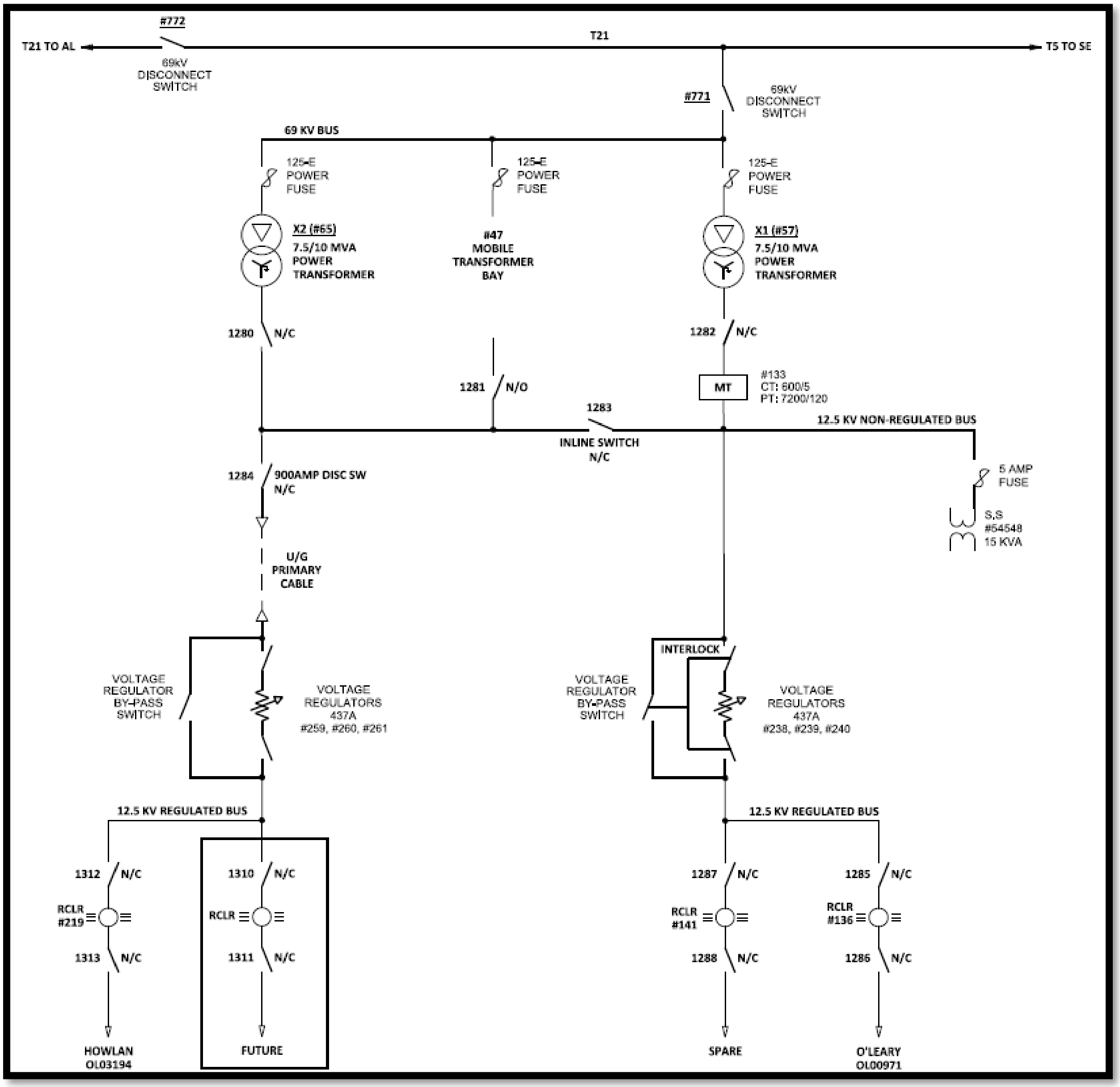


Figure 28: Single-Line Diagram of O'Leary Substation

2.1n Rattenbury Distribution System

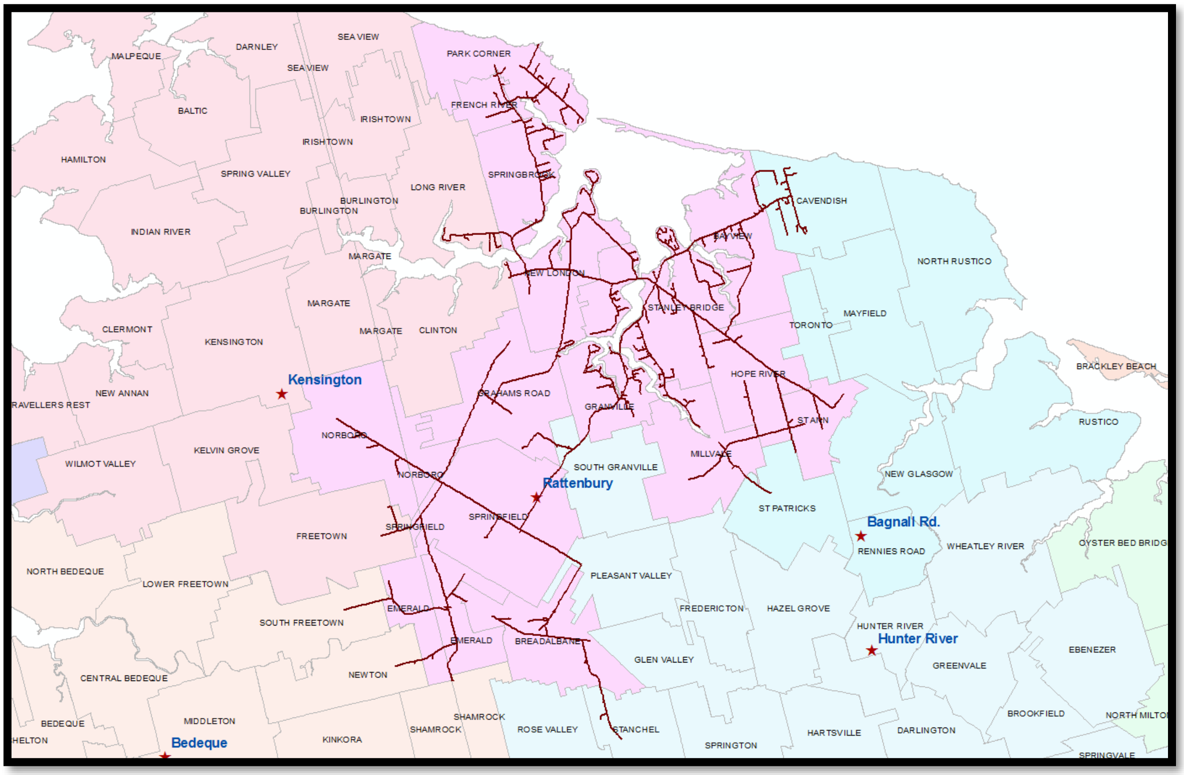


Figure 29: Service Area of Rattenbury Substation

The Rattenbury Substation ("RT") is located at 247 Rattenbury Road, Route 254, Springfield. The substation is normally fed from 69 kV transmission line T-1 out of Sherbrooke Switching Station but it can also be fed out of the West Royalty Substation. The substation has two distribution circuits, Stanley Bridge and Summerfield. The substation has set of voltage regulators (rated 328 A) and one metering tank. The substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 47. There is one substation transformer (5/6.7 MVA, Co.# 36, 1975 vintage, 69 kV – 12.5 kV) that has a summer peak load of 6.2 MVA and a winter peak load of 5.0 MVA. The summer peak load represents 124 per cent of the ONAN rating and 93 per cent of the ONAF rating. Since July 2020, the majority of Cavendish is being fed from the Bagnall Road Substation; however, to maintain reliability in the area, capacity should be available from both Bagnall Road and Rattenbury Substations. The electrical demand on the substation has increased by 39 per cent over a 10 year period and under current loading conditions, it is forecasted to surpass 6.7 MVA in 2021. A new 7.5/10 MVA transformer is planned for Rattenbury in 2021. If needed, and depending on load condition, this substation can be paralleled with Bagnall Road and/or Kensington in order to reduce the impact of a potential outage.

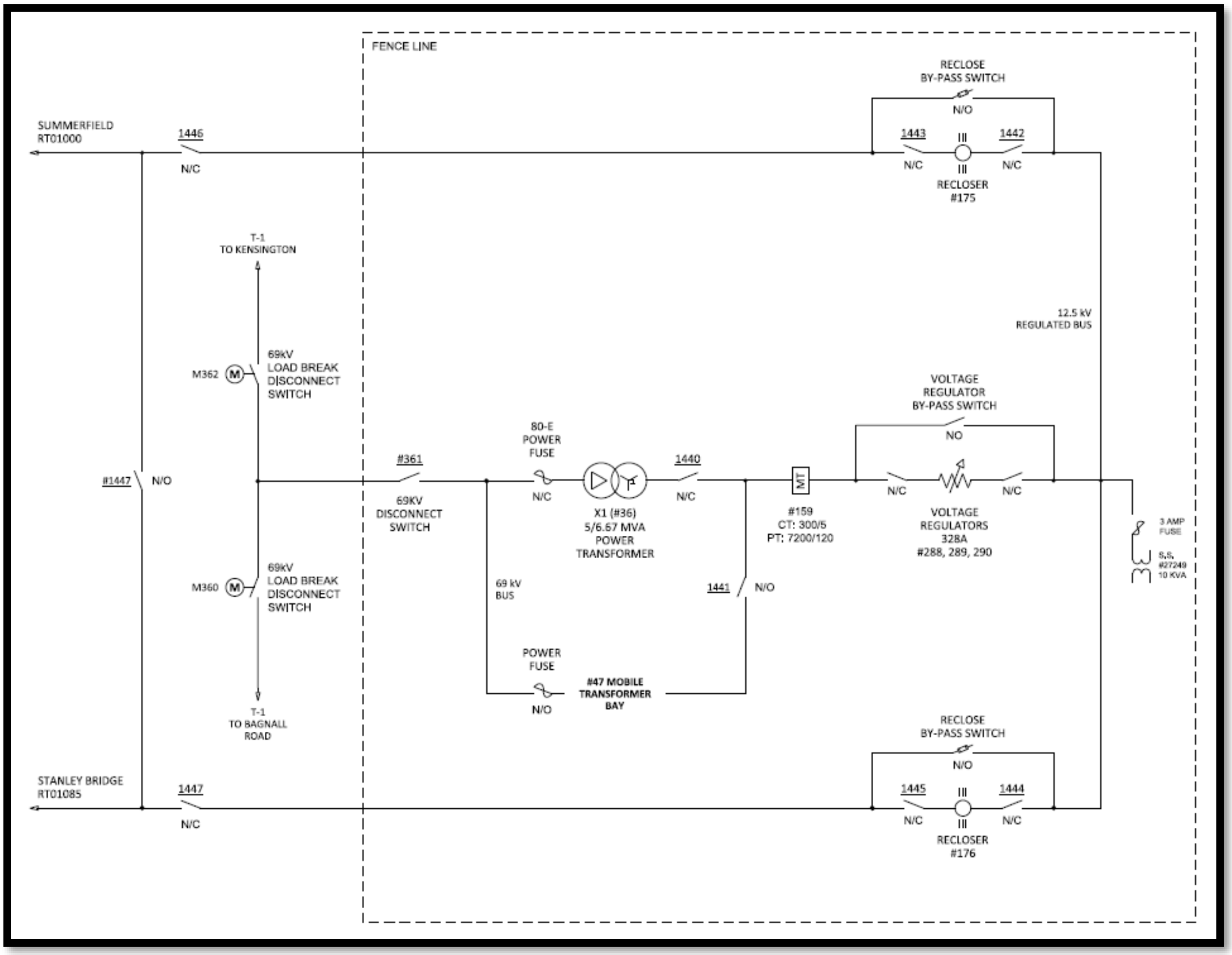


Figure 30: Single-Line Diagram of Rattenbury Substation

2.1o Scotchfort Distribution System

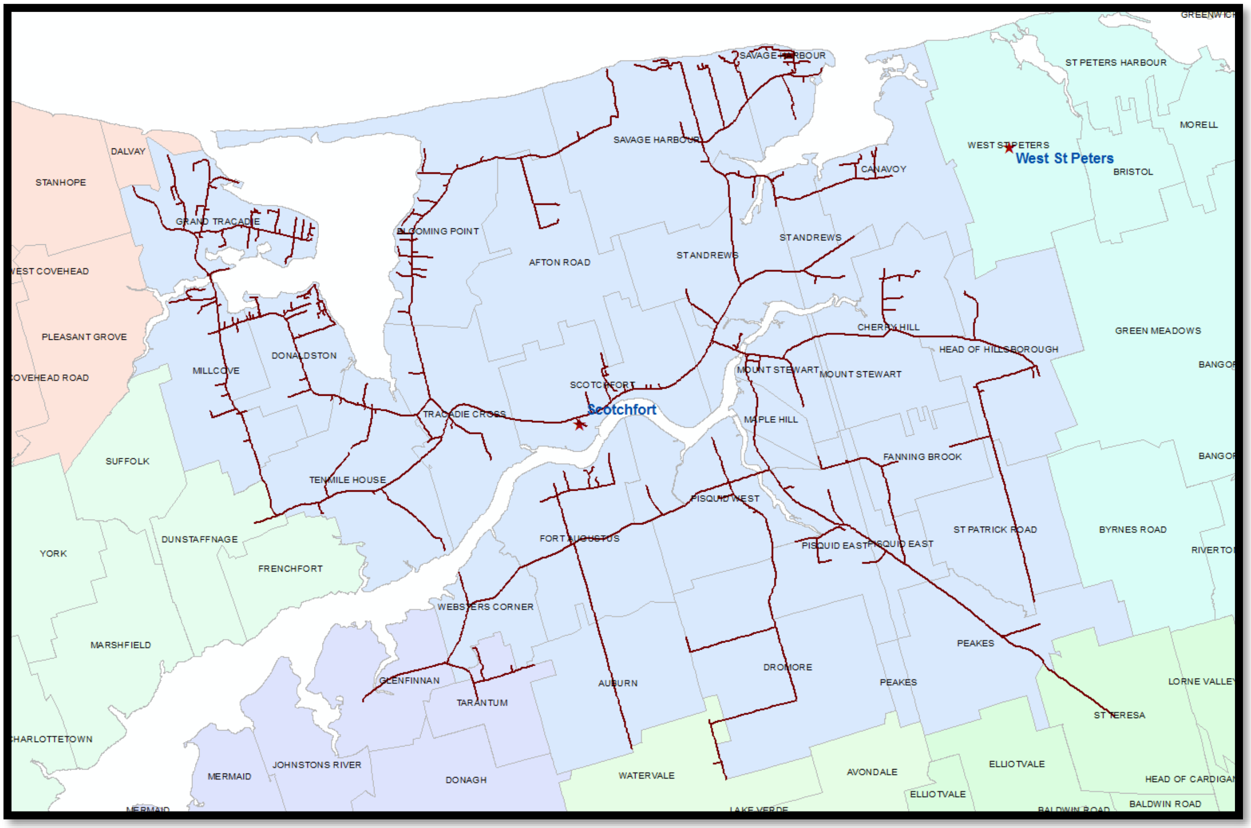


Figure 31: Service Area of Scotchfort Substation

The Scotchfort Substation ("SF") is located at 40 McBride Road in Scotchfort. The substation is fed from 69 kV transmission line T-4 out of the Lorne Valley Switching Station. The substation has two distribution circuits, Mount Stewart and Bedford. There is one substation transformer (7.5/10 MVA, Co.# 70, 2014 vintage, 69 kV – 12.5 kV). The substation has one set of voltage regulators (rated 437 A) and one metering tank. The substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 47. The summer and winter peak load is 3.6 MVA and 5.4 MVA respectively. The winter peak load represents 72 per cent of the ONAN rating and 54 per cent of the ONAF rating. If needed, and depending on load condition, this substation can be paralleled with West St. Peters and/or UPEI in order to reduce the impact of a potential outage.

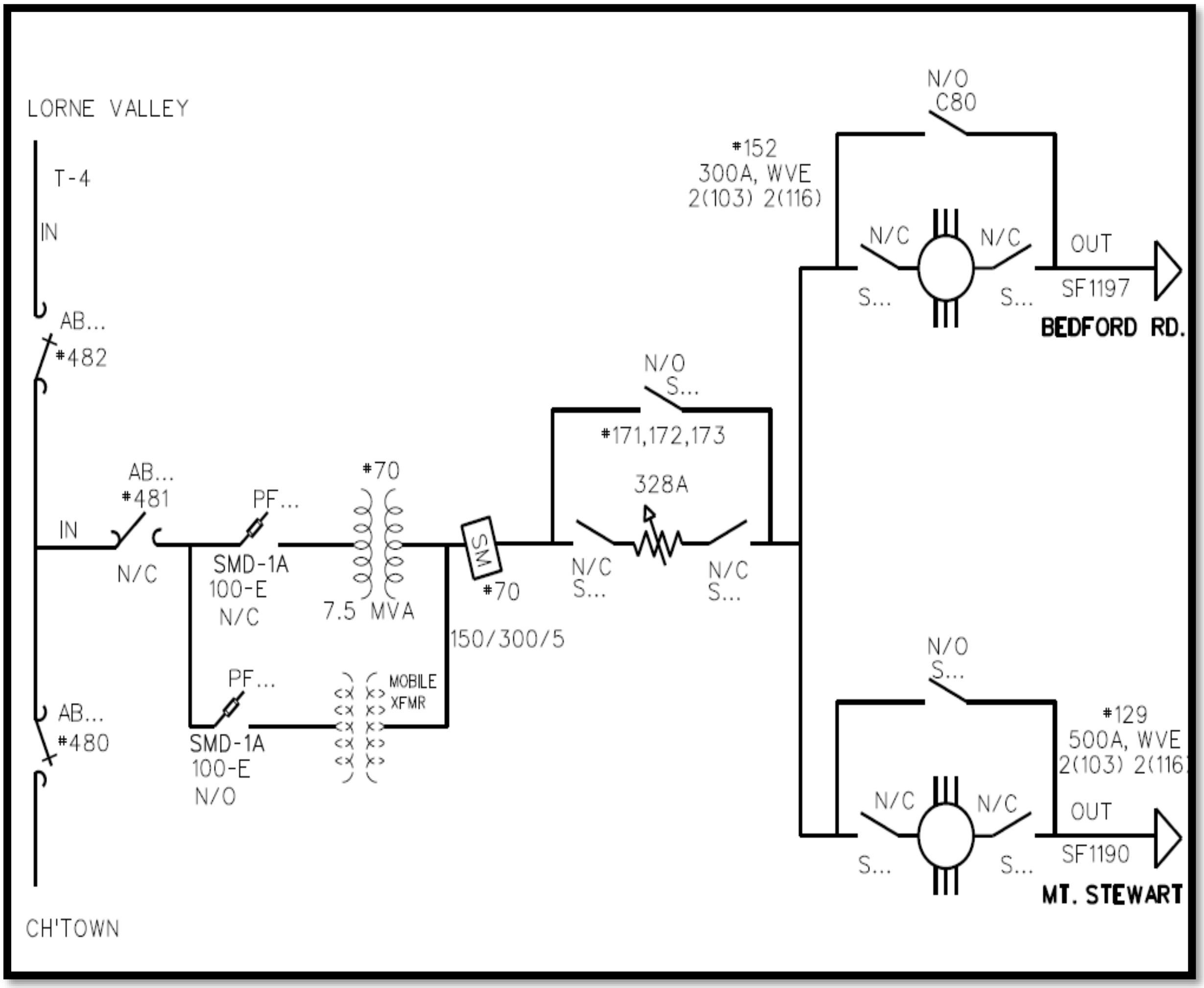


Figure 32: Single-Line Diagram of Scotchfort Substation

2.1p Souris Distribution System

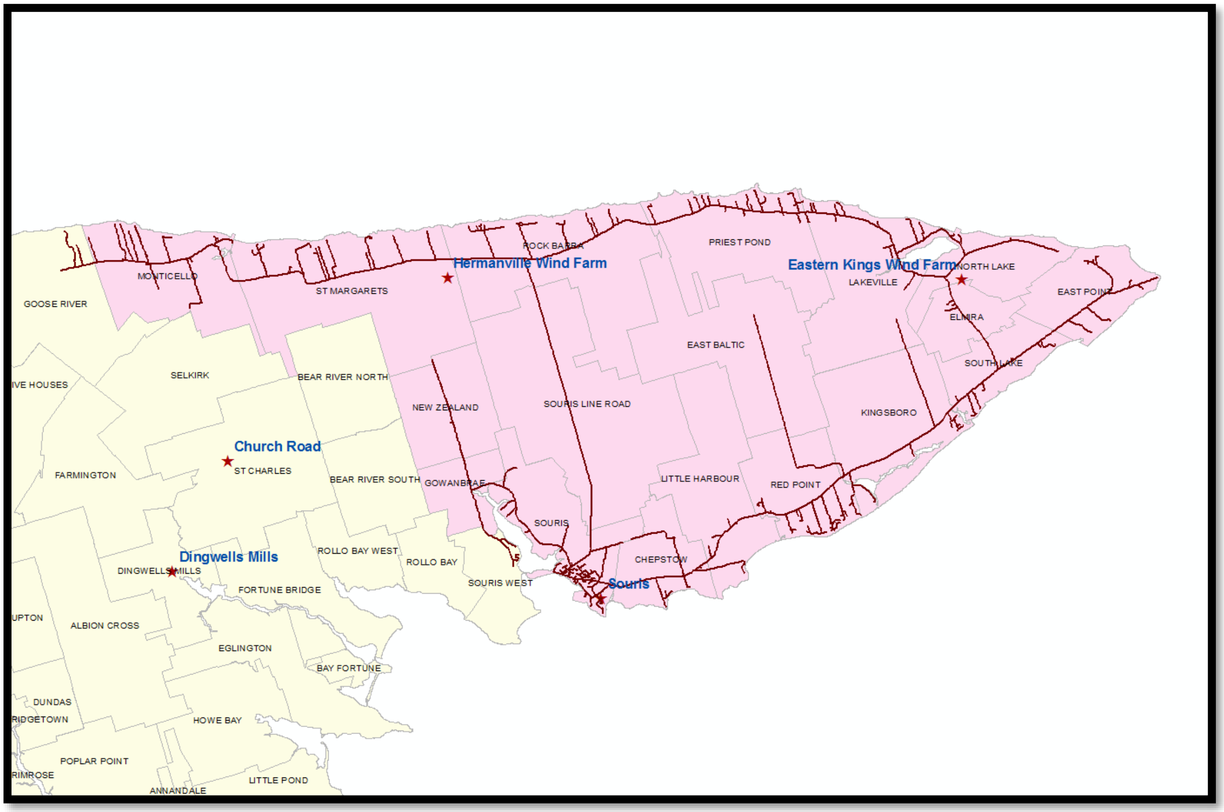


Figure 33: Service Area of Souris Substation

The Souris Substation ("SO") is located at 9 Hope Street in Souris. The substation is fed from 69 kV transmission line T-8 out of the Church Road and Lorne Valley Switching Stations. The substation has three distribution circuits, Town of Souris, Souris Food Industrial Park and East Point. There are two substation transformers ([4.0/5.97 MVA, Co.# 23, 1967 vintage, 66 kV/33 kV – 25 kV/12.5 kV] and [4.0/6.0 MVA, Co.# 28, 1971 vintage, 66 kV/33 kV – 25 kV/12.5 kV]) that are paralleled. The substation has one set of voltage regulators (rated 437 A) and two metering tanks. The substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 47. The summer and winter peak load is 6.4 MVA and 7.5 MVA respectively. The winter peak represents 94 per cent of the combined ONAN rating and 63 per cent of the combined ONAF rating.

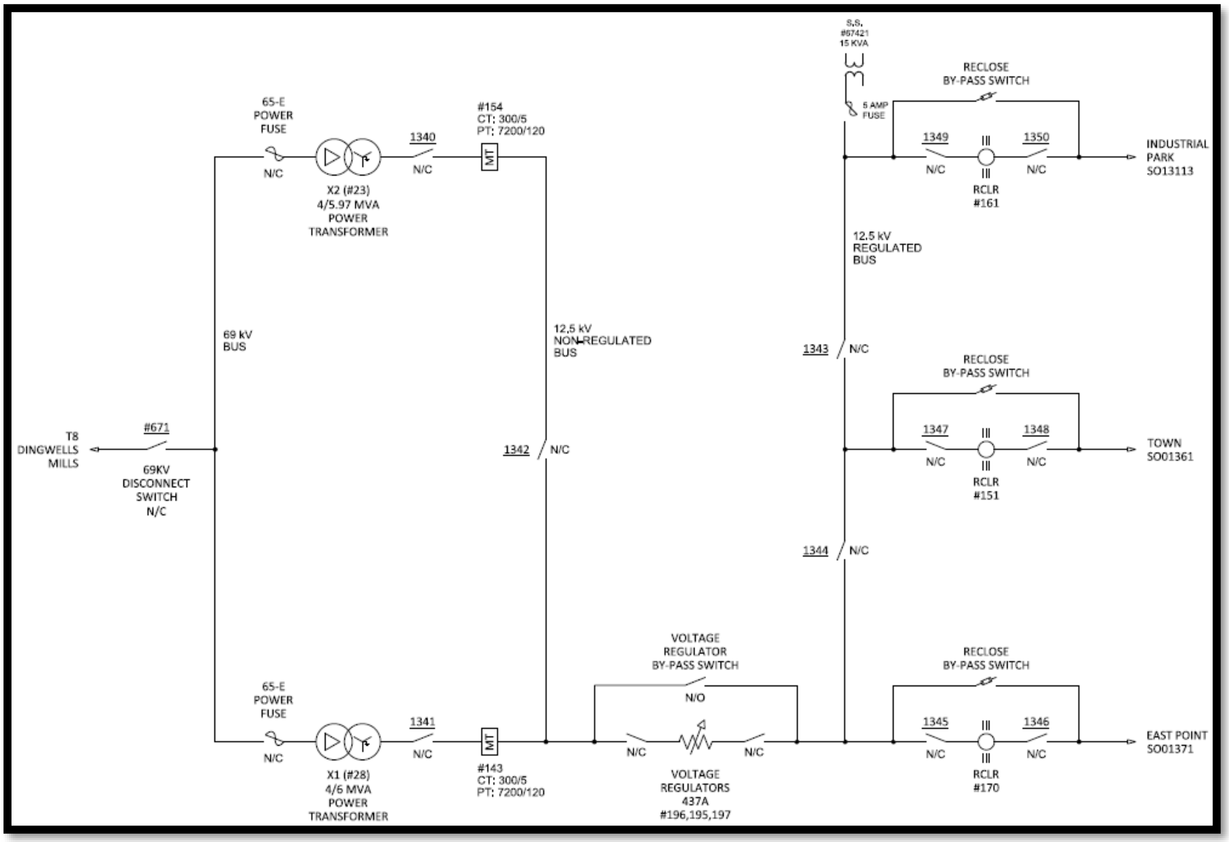


Figure 34: Single-Line Diagram of Souris Substation

2.1q St. Eleanors Distribution System

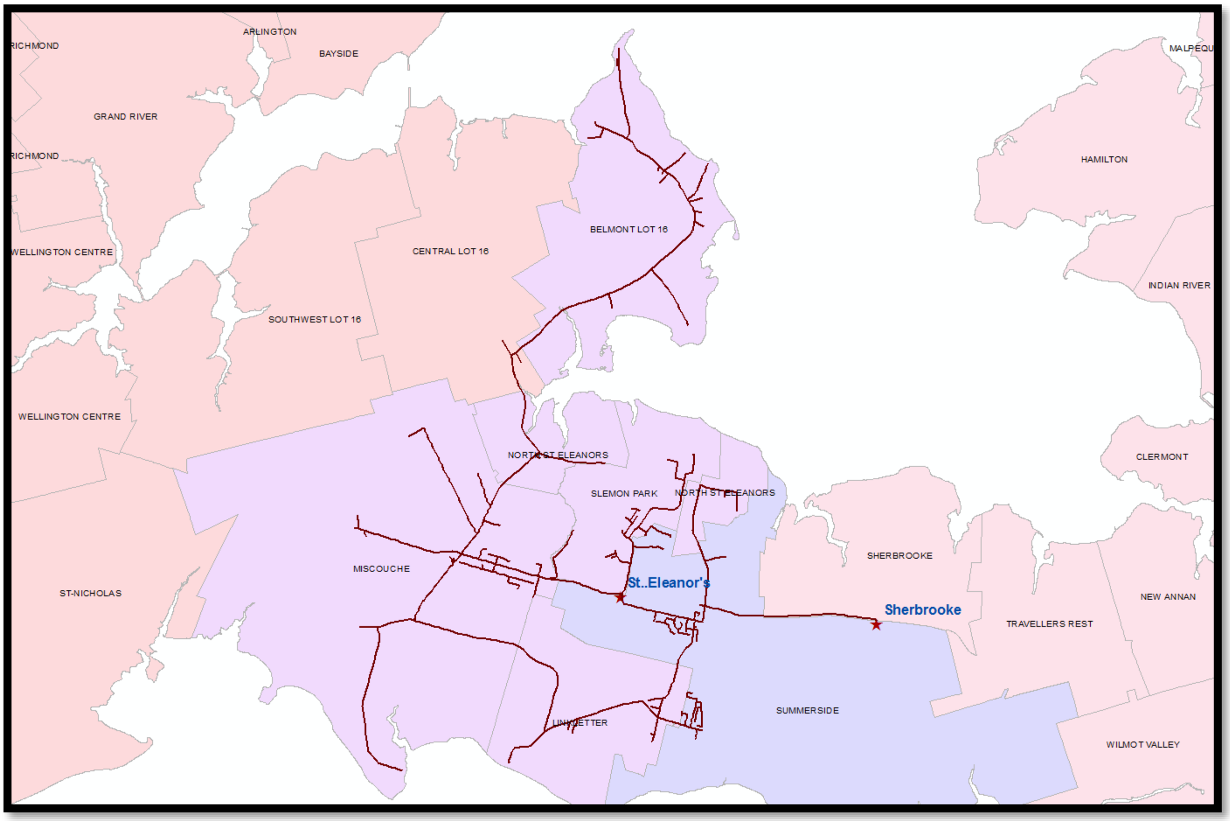


Figure 35: Service Area of St. Eleanors Substation

The St. Eleanors Substation (“SE”) is located at 230 West Drive in St. Eleanors. The substation is fed from 69 kV transmission line T-5 out of the Sherbrooke Switching Station. The substation has three distribution circuits, Miscouche, Slemon Park and Sherbrooke. The Sherbrooke circuit feeds the Company’s Sherbrooke Service Centre. There are two substation transformers (5/6.7 MVA each: [Co.# 37, 1975 vintage, 69 kV – 12.5 kV] and [Co.# 44, 1978 vintage, 69 kV – 12.5 kV]) that are paralleled. The substation has one set of voltage regulators and one metering tank. The substation is equipped with a mobile transformer bay, and can accept mobile transformer Co.# 47. The summer peak load is 5.3 MVA while the winter peak load is 6.4 MVA. The winter peak represents 64 per cent of the combined ONAN rating and 48 per cent of the combined ONAF rating.

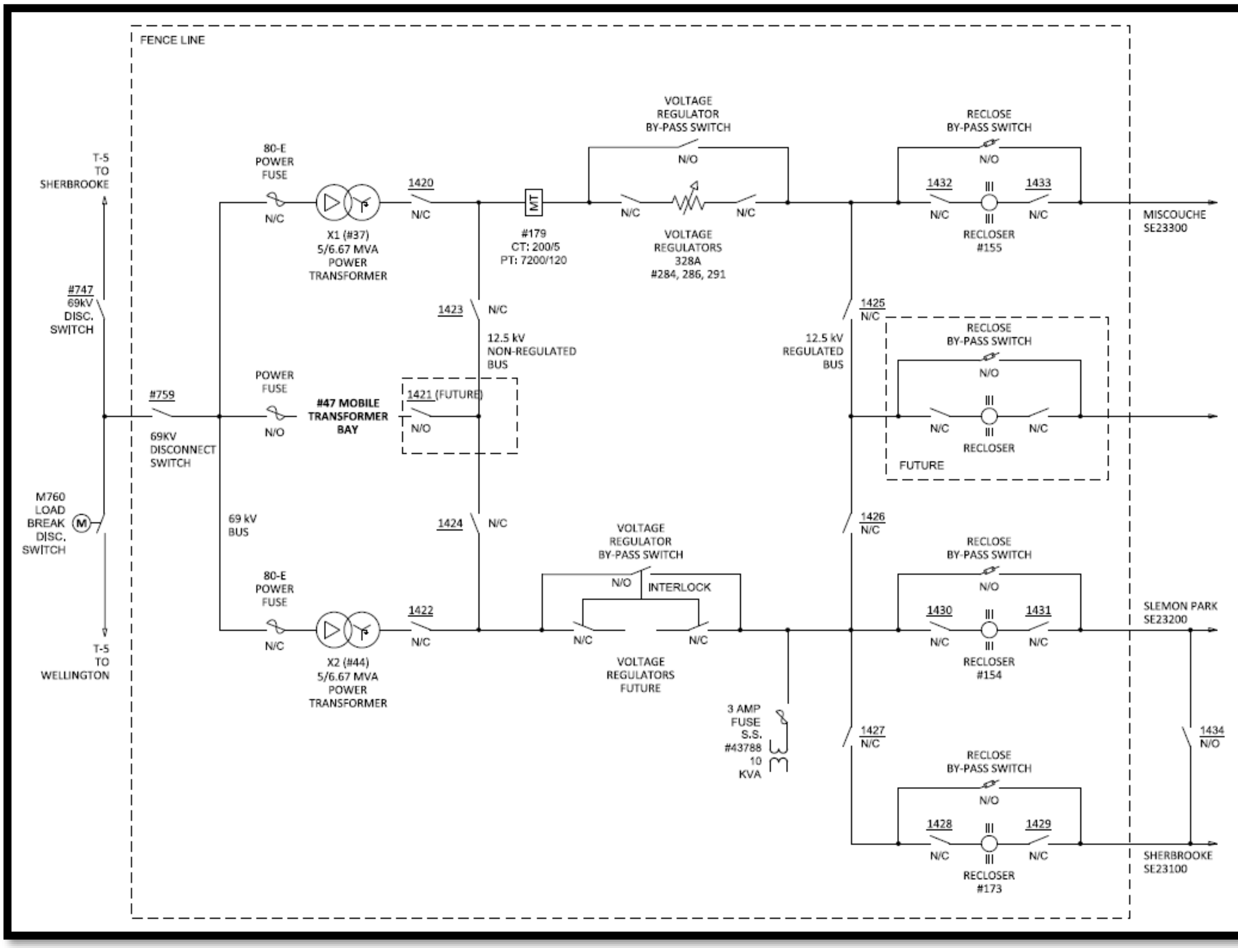


Figure 36: Single-Line Diagram of St. Eleanors Substation

2.1r UPEI Distribution System

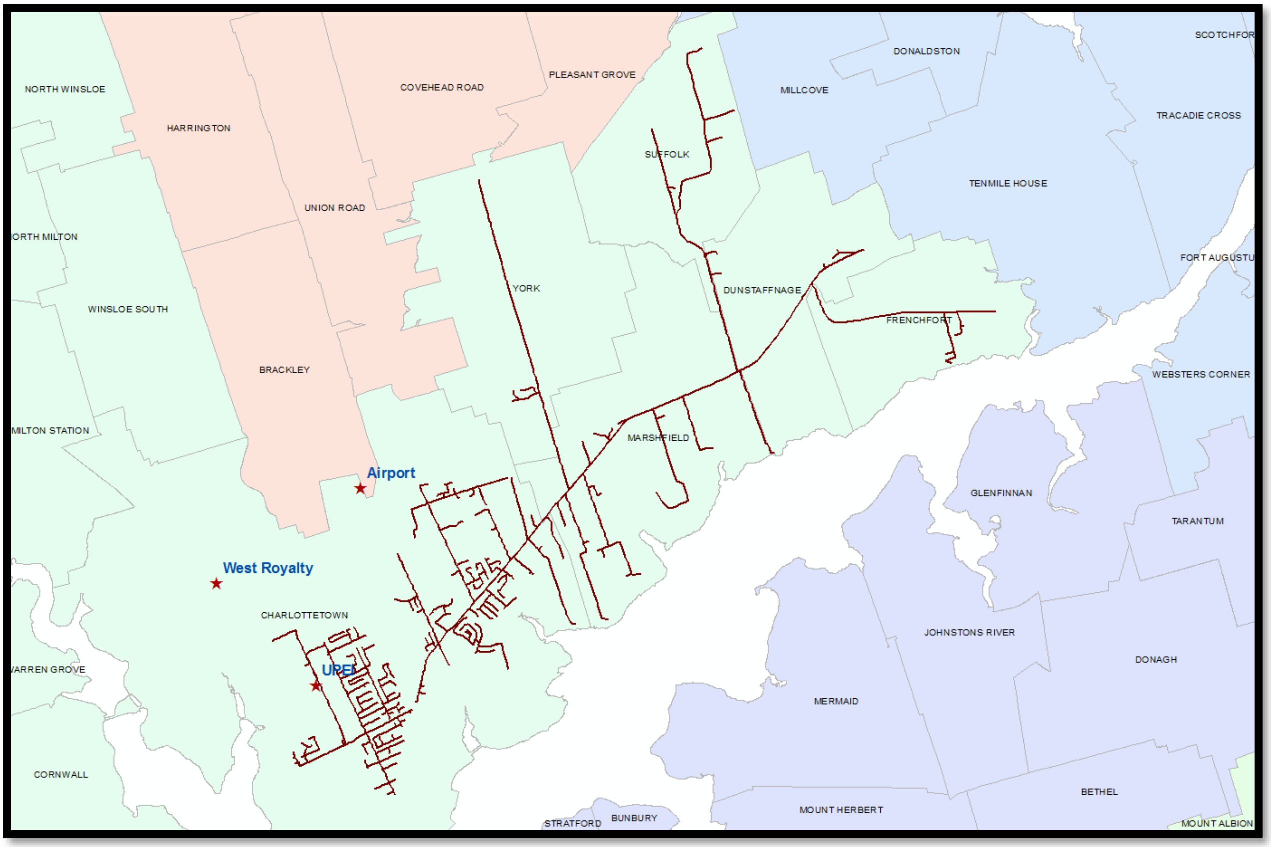


Figure 37: Service Area of UPEI Substation

The UPEI Substation ("UP") is located on the University of PEI ("UPEI") campus in Charlottetown. The substation is fed from 69 kV transmission line T-13 out of the West Royalty and Charlottetown Plant Substations. The substation has four distribution circuits, Pine Drive, Charlottetown Mall, Belvedere and UPEI. There is one substation transformer (15/20 MVA, Co.# 74, 2014 vintage, 69 kV – 13.8 kV) providing energy at 13.8 kV. The substation has an on load tap changer for voltage regulation and uses bus PT's and transformer CT's for metering. The substation is not equipped with a mobile transformer bay. The summer peak load is 12.8 MVA while the winter peak load is 14.7 MVA. The winter peak represents 98 per cent of the ONAN rating and 74 per cent of the ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Charlottetown Plant and/or West Royalty in order to reduce the impact of a potential outage.

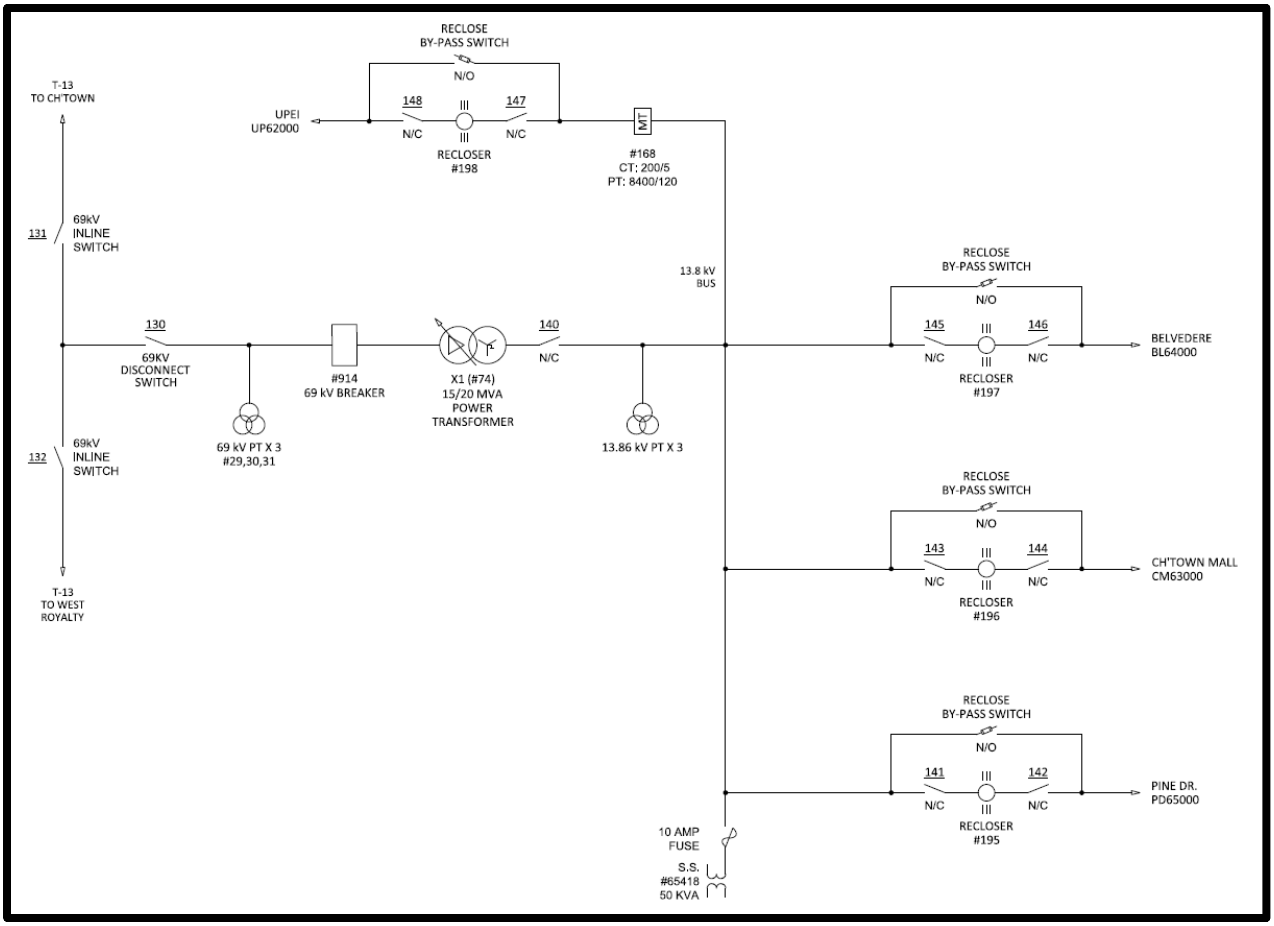


Figure 38: Single-Line Diagram of UPEI Substation

2.1s Victoria Cross Distribution System

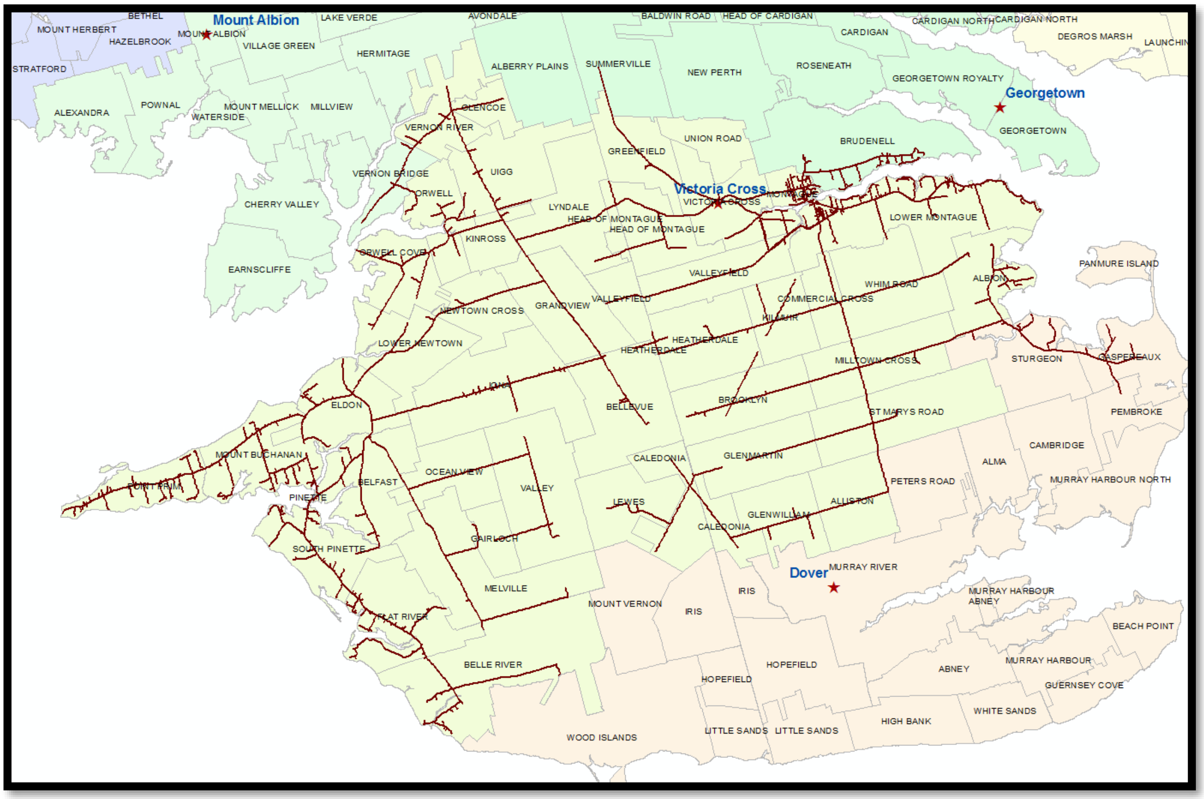


Figure 39: Service Area of Victoria Cross Substation

The Victoria Cross Substation ("VC") is located at 5400 Sparrows Road - Route 320 in Montague. The substation is fed from 69 kV transmission line T-10 out of the Lorne Valley Switching Station. Victoria Cross has two distribution voltages 12.5 kV and 25 kV. The substation has two 25 kV distribution circuits, Commercial Road and Eldon-Belfast, and two 12.5 kV distribution circuits, Montague and Valleyfield. There are two substation transformers (7.5/10 MVA each: [Co.# 52, 1981 vintage, 69 kV – 25 kV] and [Co.# 68, 2010 vintage, 69 kV – 12.5 kV]) that are not paralleled. The substation has two voltage regulators (one rated 300 A on the 25 kV side and one rated 437 A on the 12.5 kV side) and two metering tanks. The Victoria Cross Substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 47. The summer and winter peak load on the 69 kV - 12.5 kV transformer is 5.1 MVA and 6.2 MVA respectively. The winter peak represents 83 per cent of the ONAN rating and 62 per cent of the ONAF rating. The summer and winter peak load on the 69 kV - 25 kV transformer is 4.7 MVA and 6.5 MVA respectively. The winter peak represents 87 per cent of the ONAN rating and 65 per cent of the ONAF rating. If needed, and depending on load condition, the substation's 12.5 kV customers can be paralleled with Georgetown in order to reduce the impact of a potential outage.

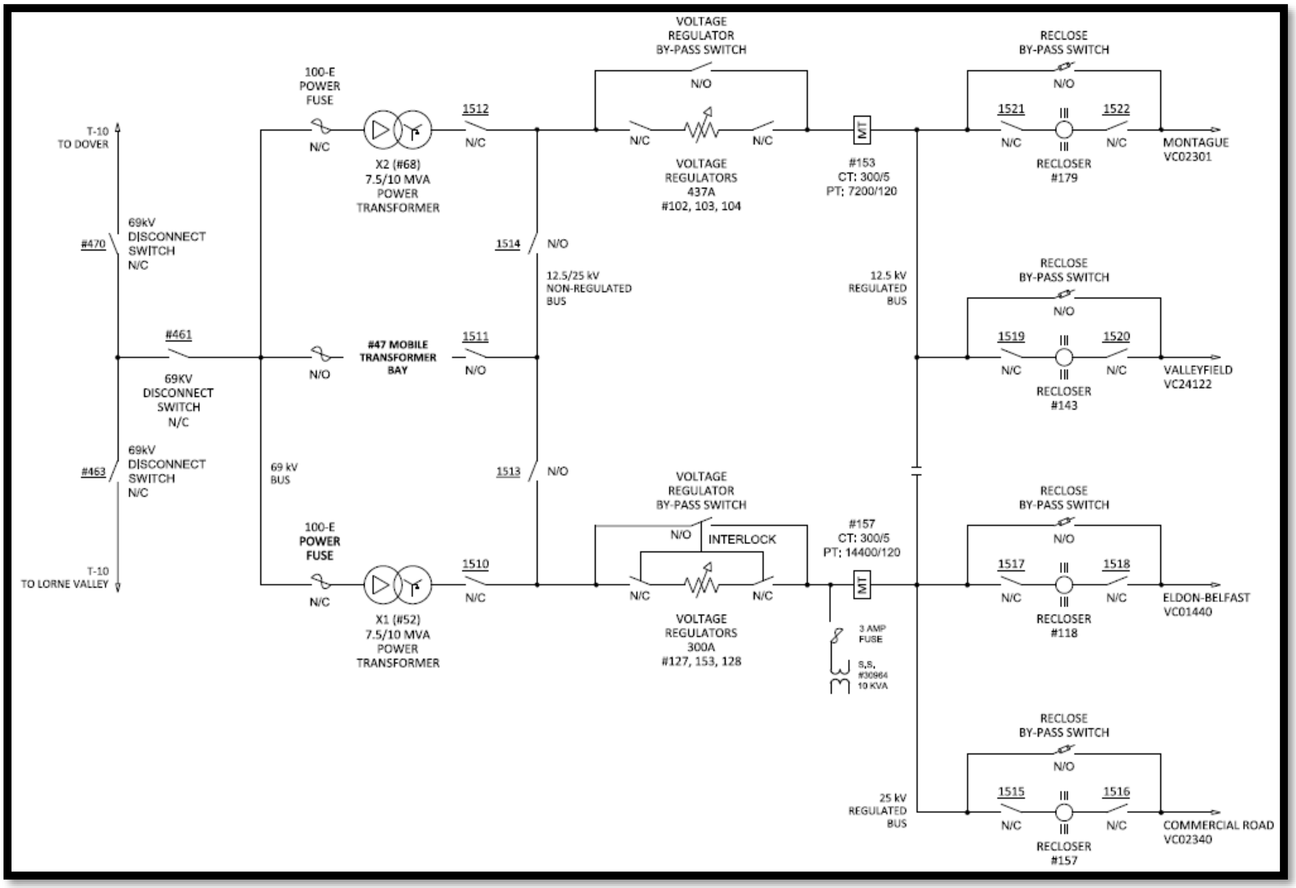


Figure 40: Single-Line Diagram of Victoria Cross Substation

2.1t Wellington Distribution System

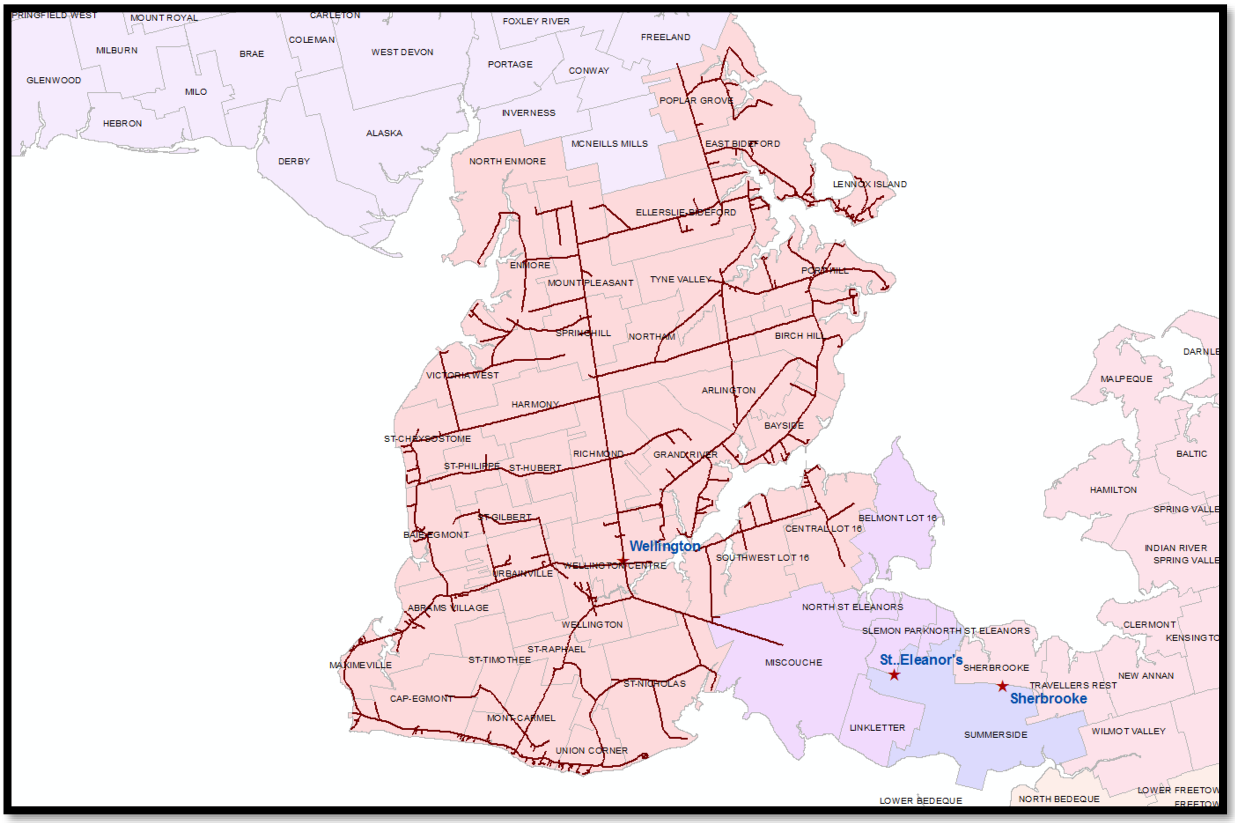


Figure 41: Service Area of Wellington Substation

This Wellington Substation ("WL") is located at 30567 Western Road, Route 2 in Wellington Centre. The substation is fed from 69 kV transmission line T-5 out of the Sherbrooke Switching Station. Transmission line T-21 originates from the Wellington Substation to feed further west. The substation has three circuits, St. Nicholas, Wellington West and Abrams Village, and was built with a provision for a fourth feeder. There is one substation transformer (7.5/10 MVA, Co.# 80, 2017 vintage, 69 kV – 12.5 kV). The substation has an on load tap changer for voltage regulation and uses bus PT's and transformer CT's for metering. The substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 79. The summer and winter peak load is 6.7 MVA and 8.9 MVA respectively. The winter peak is 119 per cent of the ONAN rating and 89 per cent of the ONAF rating. If needed, and depending on load condition, this substation can be paralleled with O'Leary in order to reduce the impact of a potential outage.

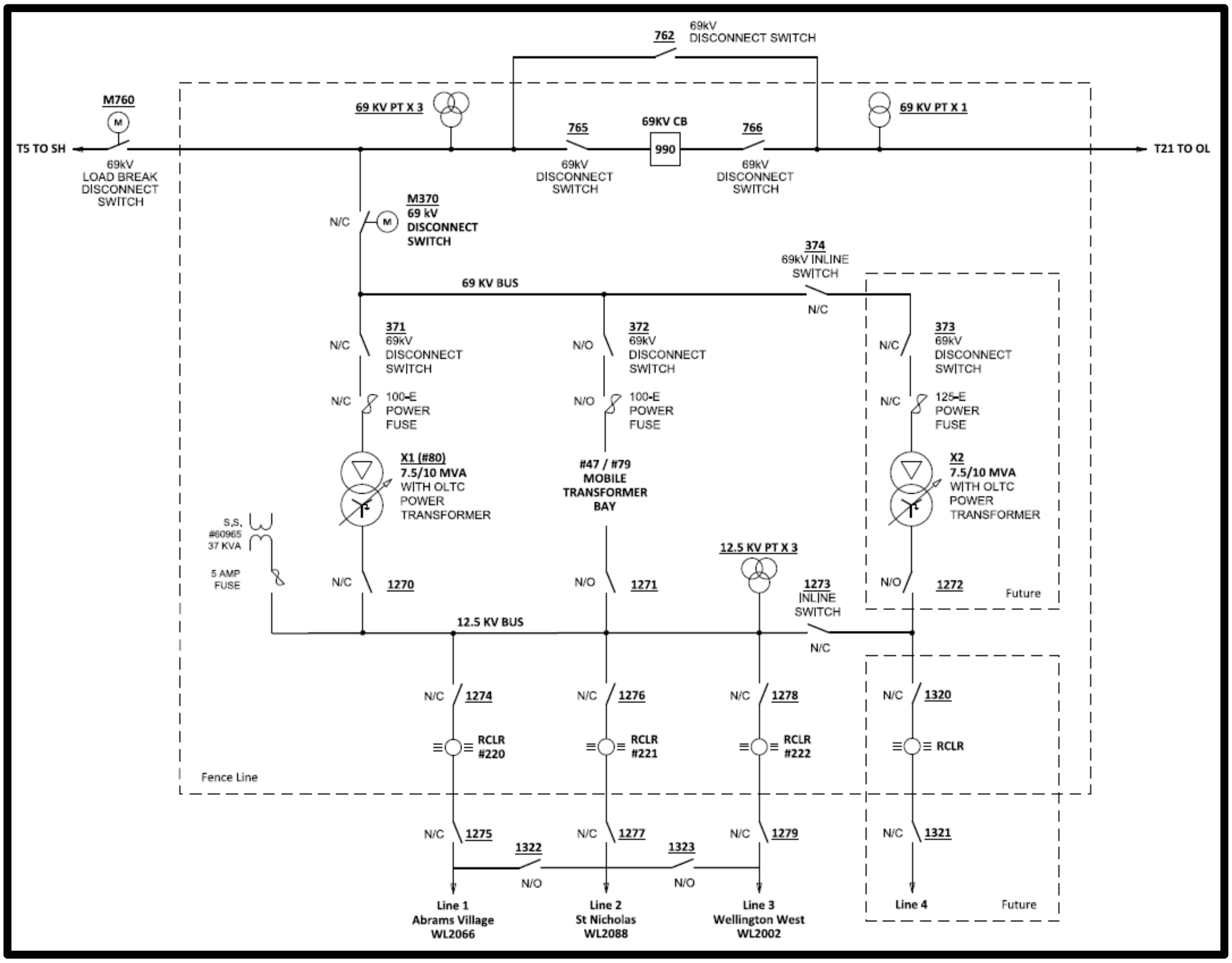


Figure 42: Single-Line Diagram of Wellington Substation

2.1u West Royalty City Distribution System

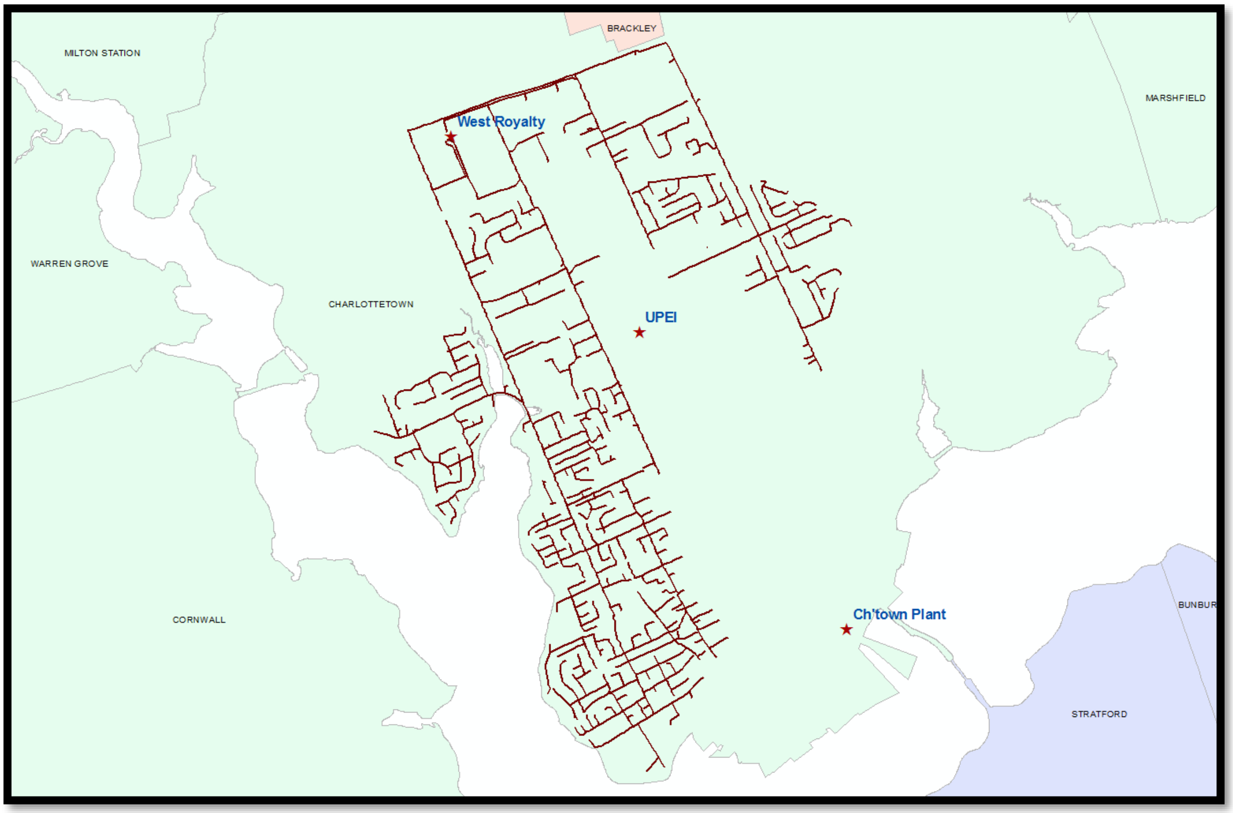


Figure 43: Service Area of West Royalty Substation

The West Royalty Substation ("WR") is located at 30 Sherwood Road in Charlottetown. The substation is fed from a 138 kV bus (supplied by Y-109/Y-111/Y-104) and a 69 kV bus (supplied by T-1/T-13/T-15). The substation has five 13.8 kV distribution circuits, Inkerman, Sherwood, Queens Arms, Mount Edward and University Avenue. There are two 13.8 kV substation transformers (15/20 MVA each: [Co.# 31, 1972 vintage, 69 kV – 13.8 kV] and [15/20 MVA, Co.# 42, 1976 vintage, 69 kV – 13.8 kV]) that are paralleled. The substation is not equipped with a mobile transformer bay. The summer and winter peak load is 19.8 MVA and 19.8 MVA respectively. The peak load represents 66 per cent of the combined ONAN rating and 50 per cent of the combined ONAF rating. If needed, and depending on load condition, this substation can be paralleled with UPEI and/or Charlottetown Plant Substations in order to reduce the impact of a potential outage.

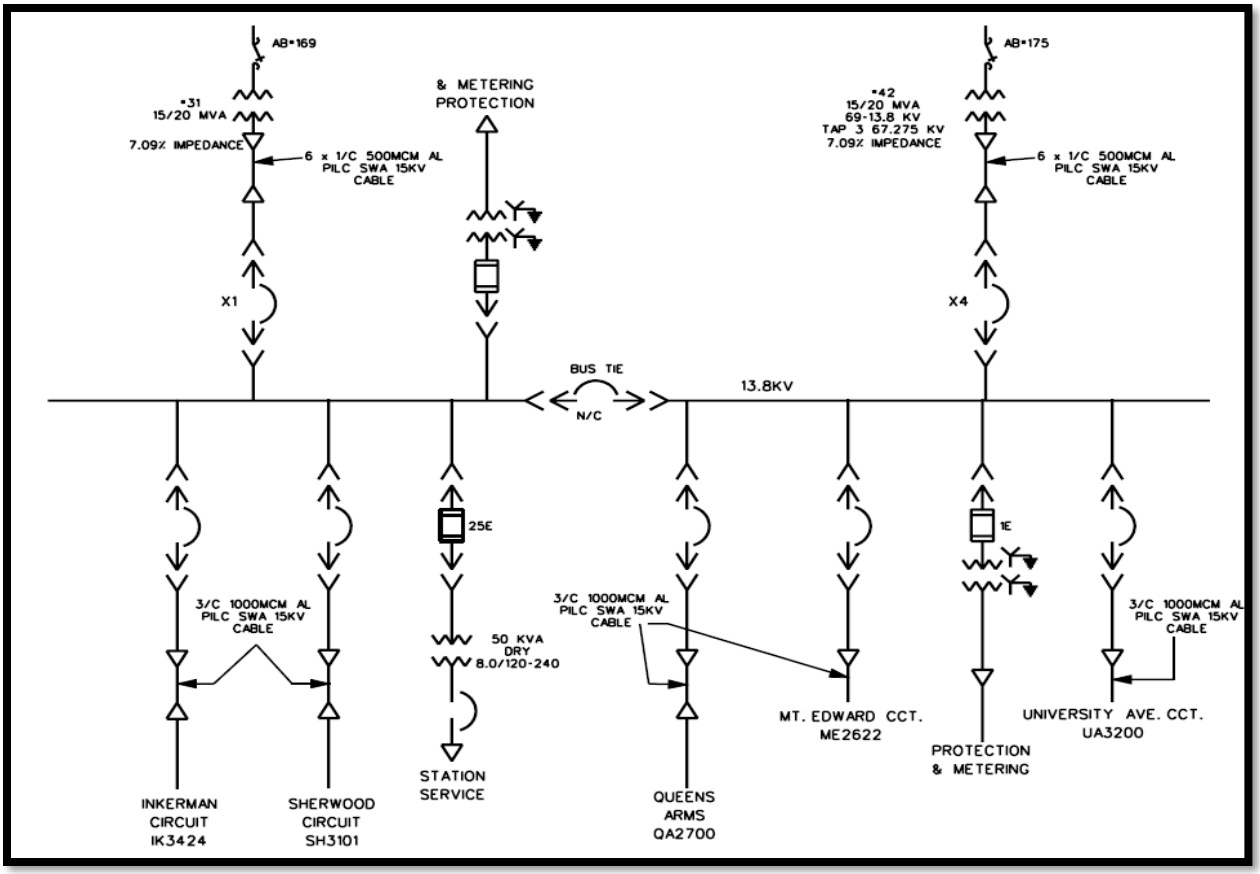


Figure 44: Single-Line Diagram of West Royalty Substation

2.1v West Royalty Rural Distribution System

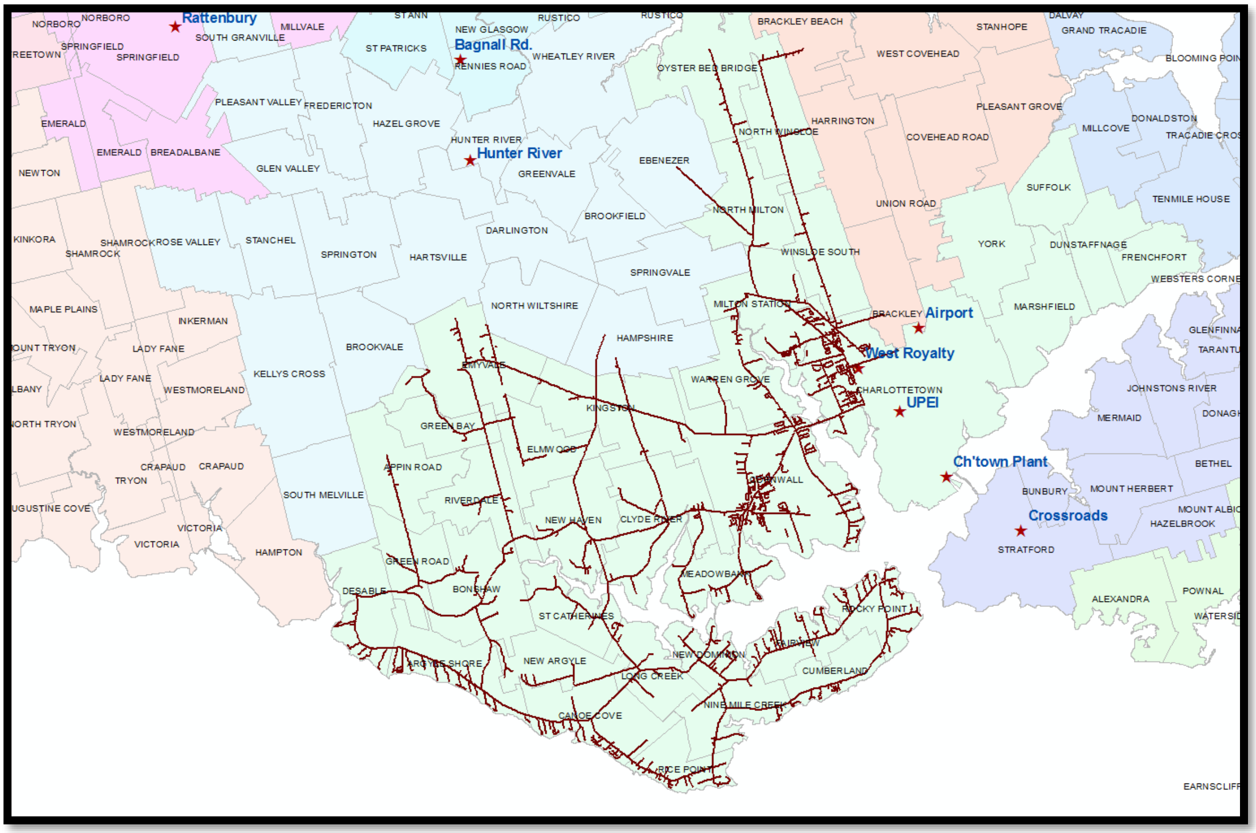


Figure 45: Service Area of West Royalty Rural Substation

The West Royalty Substation also has three 25 kV distribution circuits feeding Milton-Brackley, Bonshaw and the West Royalty Business Park. There are two substation transformers (15/20 MVA each: [Co.# 56, 1994 vintage, 69 kV – 25 kV/13.8 kV] and [Co.# 62, 1972 vintage, 69 kV – 25 kV/13.8 kV]) that are paralleled. There is no mobile transformer bay in the West Royalty Substation. The summer and winter peak load is 22.0 MVA and 31.7 MVA respectively. The winter peak is 106 per cent of the combined ONAN rating and 79 per cent of the combined ONAF rating. If needed, and depending on load condition, this substation can be paralleled with the Airport Substation in order to reduce the impact of a potential outage.

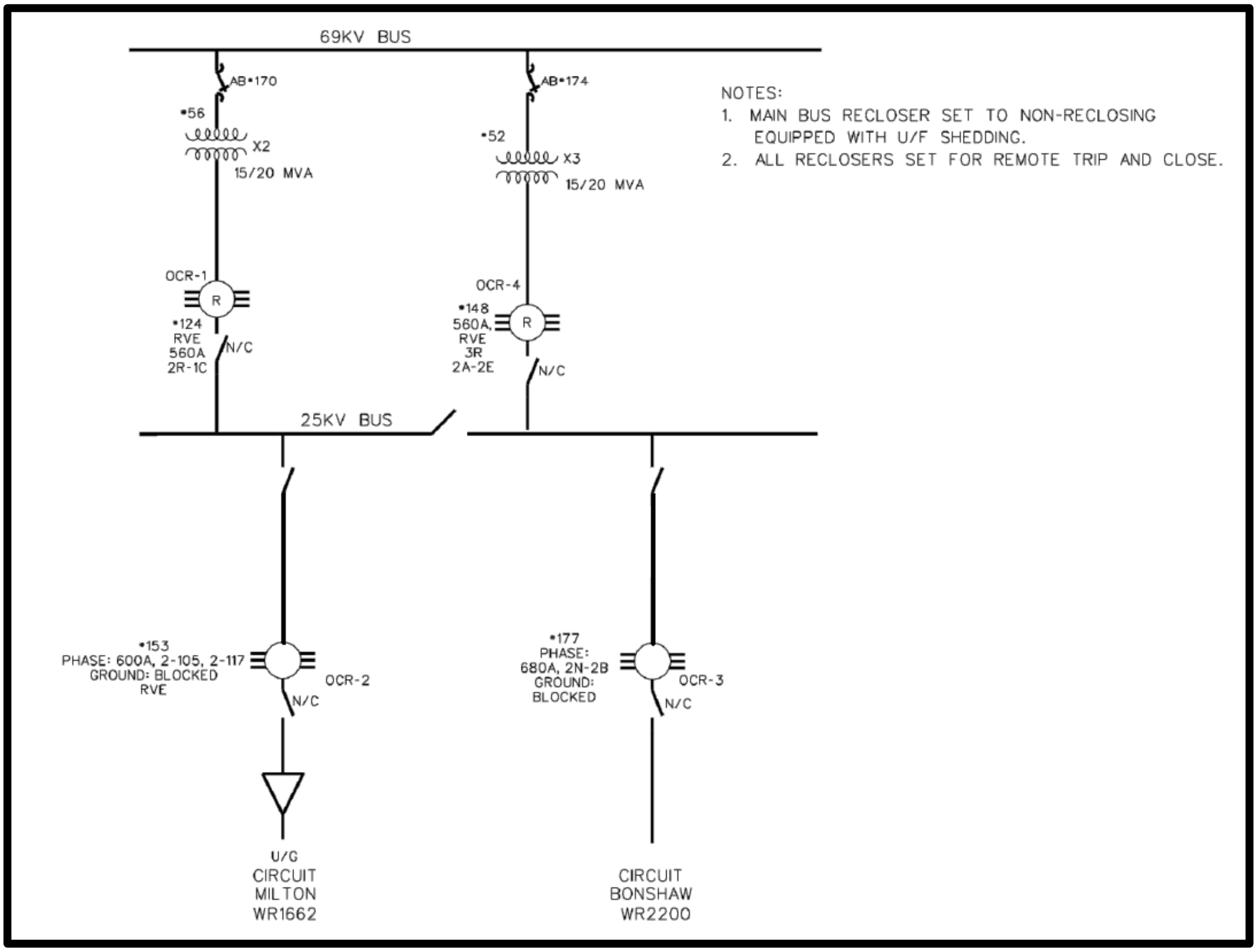


Figure 46: Single-Line Diagram of West Royalty Rural Substation

2.1w West St. Peters Distribution System

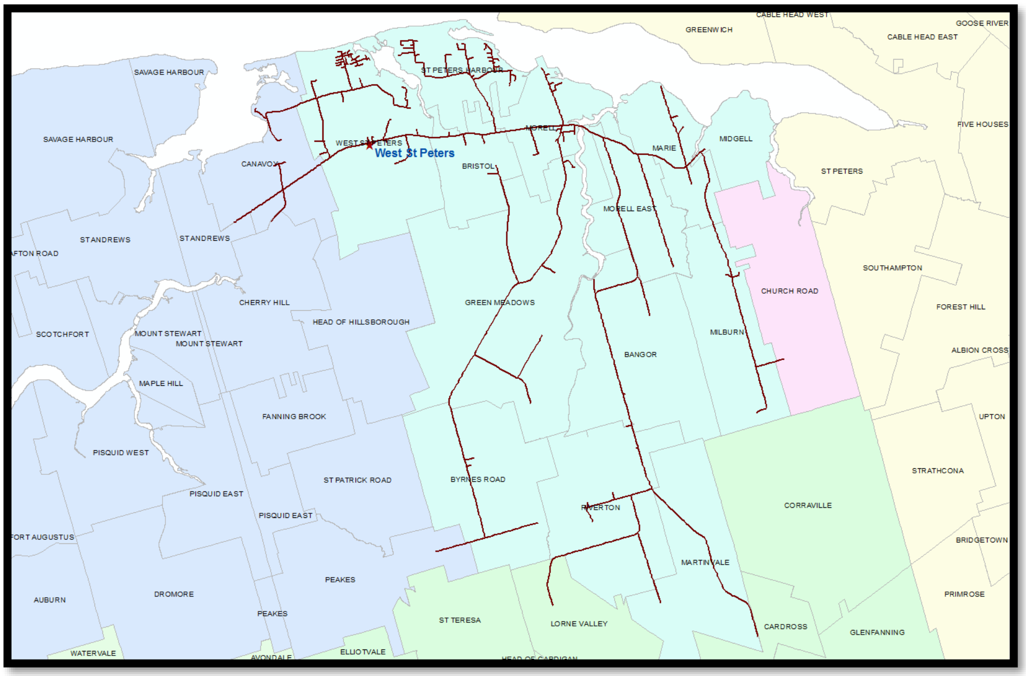


Figure 47: Service Area of West St. Peters Substation

The West St. Peters Substation ("WP") is located at 8807 St. Peters Road, West St. Peters. The substation is fed from 138 kV transmission line Y-104 that is out of the Church Road Switching Station and West Royalty Substation. The substation has three distribution circuits, Morell, St. Andrews and Wyman's. The substation has an on load tap changer for voltage regulation and uses bus PT's and transformer CT's for metering. The substation is equipped with a mobile transformer bay, and can accept mobile transformer Co.# 79. There is one substation transformer (7.5/10 MVA, Co.# 75, 2015 vintage, 13.8 kV – 12.5 kV) that has a summer peak load of 7.8 MVA and a winter peak load of 4.4 MVA. The summer peak load represents 104 per cent above the ONAN rating and 78 per cent of the ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Dingwells Mills and/or Scotchfort in order to reduce the impact of a potential outage.

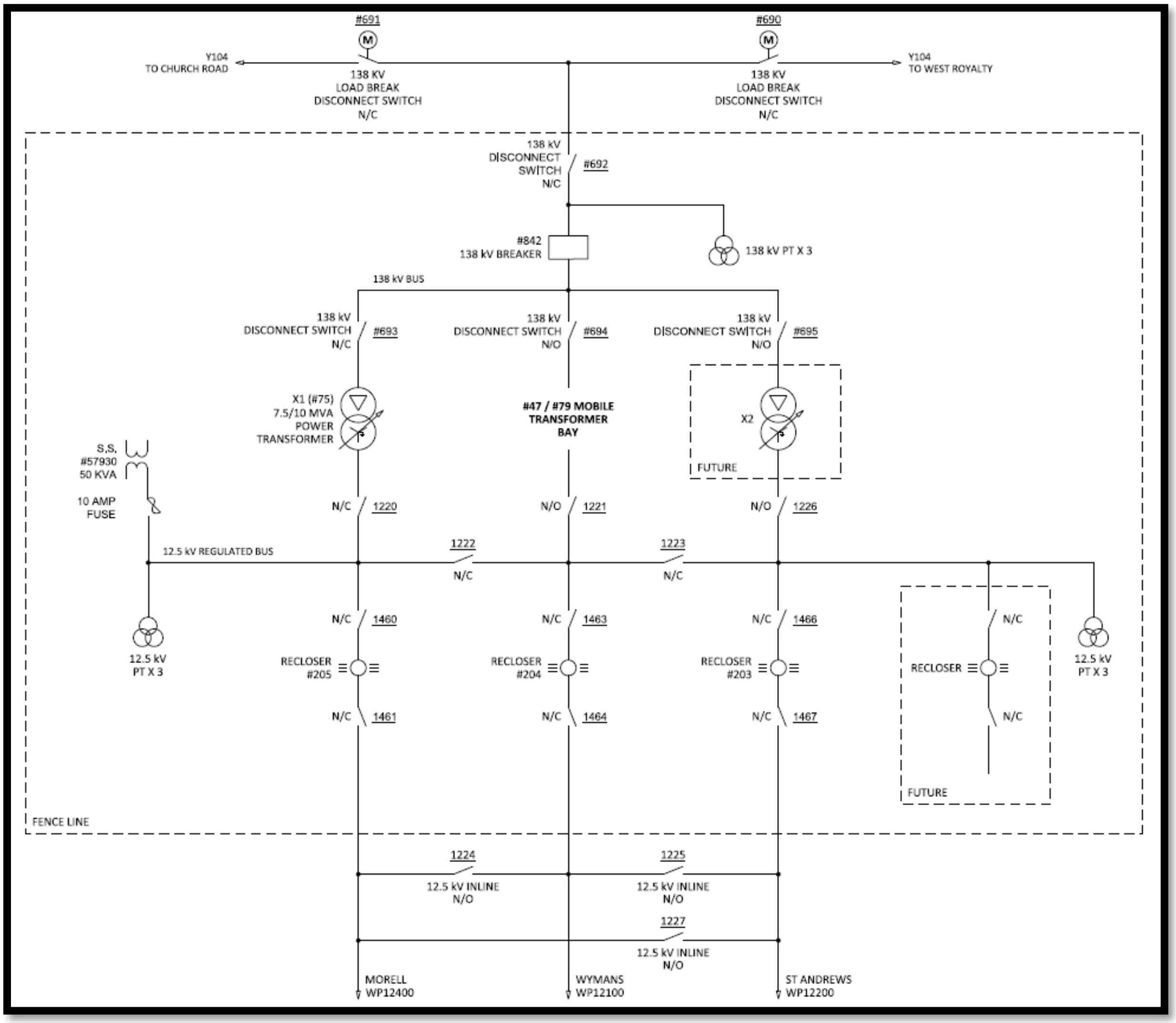


Figure 48: Single-Line Diagram of West St. Peters Substation

2.2 Summary of Distribution Managed Assets

The following is information that is accurate as of July 2020:

Table 1 Maritime Electric's Distribution Assets	
Customers	**79,497**
System Peak	**287 MW**
Distribution Lines	**5,372 km**
a. Overhead Lines	5,329 km
Three Phase	1,294 km
Single Phase	4,035 km
b. Underground Lines	43 km
Three Phase	11 km
Single Phase	32 km
Poles	144,900
Distribution Substations	**22**
Substation Transformers	32
Distribution Transformers	37,956
Padmounts	1,154
Polemounts	36,802
Reclosers	100
Voltage Regulators	142
Capacitor Banks	144
Metering Tanks	86

3.0 DISTRIBUTION ASSETS

3.1 Identification of Managed Assets

Maritime Electric has had a Maintenance and Asset Replacement Program underway for some time. The program includes the assessment of the condition of equipment and development of an asset maintenance and replacement cycle for distribution equipment. Asset inspection and maintenance cycles include four categories: visual inspections, mechanical operation inspections, electrical testing, and overhaul maintenance. Overhaul maintenance incorporates a scheduled shut down and de-energization of equipment.

3.2 Geographic Information Systems

For the most part, Maritime Electric's poles, transformers, meters, line connectivity and street lights are managed within a corporate Customer Information System ("CIS"). Employees access the data in various ways including CIS screens, reports and the Company's geographic information system ("GIS System"). The data is also used by other systems including the Outage Management and Work Management Systems, for power system planning and with AutoCAD design tools.

3.3 Overhead Distribution Managed Assets

The following is a listing and brief description of each type of Distribution Managed Asset ("DMA") at Maritime Electric:

Overhead Conductor

Conductors, also called wires or cables, run from pole to pole or pole to building, and carry the current from the source to the customers. Overhead conductor has several different characteristics:

- Metal or Alloy: Older conductors were mostly copper, but most modern applications use aluminum or aluminum alloys to save weight and cost;
- Size/Gauge: The size of the wire is selected based on power quality and reliability. Cost of losses calculations are also considered as losses are usually much more limiting than maximum current allowances. Larger conductors cost more, weigh more, and can take longer to install, but they can carry more current (i.e., they have a higher ampacity) and can have a longer useful life;
- Insulation: Some conductors have one or more layers of insulation on them. This is necessary if they are bundled together or are installed in a location where they can be expected to be contacted by vegetation or the public. The bundled cable has two insulated and one bare conductor, and is used for supplying a typical 'house service'. Most primary/high voltage conductors are bare, as this saves costs and weight; and

- Single or Bundled: At lower voltages, to save space and add strength, more than one conductor may be twisted or lashed into a 'bundle'. This is most common for secondary or service wires.

Poles

Constructed of wood, steel, and occasionally concrete or resin composites, poles form the backbone of the overhead distribution system. Wooden poles are used in over 99 per cent of all cases. For distribution purposes, these range in height from 25' (7.6 m) to 75' (22.8 m). The typical height for a single circuit three phase pole is 45' (13.7 m). Poles come in several standard strengths known as classes, as defined by Canadian Standards Association ("CSA") specifications. A new wooden pole can be expected to last 50 years from the time of installation before it reaches the end of its useful life through deterioration, although it may be removed or replaced before that time as needs change.

Framing Assemblies

Framing assemblies are assorted hardware components installed on a pole that provide mechanical support and clearances, and electrical isolation/insulation for the various conductors and equipment required on an overhead distribution line.

It can include cross arms, insulators, brackets, bolts, washers, nuts and other hardware. Framing assemblies also include guying and anchors as required.

It should be noted that the specific choice of some of these components, such as insulators, will vary depending on the required voltage of the system.

Substation Transformers

Substation transformers are used to transform electricity from a transmission voltage to a distribution voltage. Typically, this will be a 10 MVA transformer used to transform electricity from a primary voltage (such as 69 kV) to a secondary voltage (such as 12.5 kV, 13.8 kV or 25 kV) useful to supply thousands of customers. New transformers now have on load tap changers. These tap changers ensure safe voltages are supplied to customers, and replace voltage regulators in substations. Currently the following substations have transformers with on load tap changers: UPEI, Wellington, Bagnall Road, Mount Albion, Airport and West St. Peters.

Mobile Transformers

Mobile transformers are used to transform electricity from a transmission voltage to a distribution voltage. The transformer and related equipment are on a trailer and can be installed in a substation if the substations transformer fails. Maritime Electric owns two mobile transformers:

One 10 MVA, 69 kV – 25 kV/12.5 kV, Co.# 47; and
One 10 MVA, 138 kV/69 kV – 25 kV/12.5 kV, Co.# 79.

Distribution Transformers and Voltage Regulators

Distribution transformers are used to transform electricity from one voltage to another. Typically, this will be from a primary voltage (such as 12.5 kV, 13.8 kV or 25 kV) to a secondary voltage (such as 120/240 Volts ["V"]) useful to one or more customers.

Pole top transformers can be found in a variety of sizes, ranging from 3 kVA to 100 kVA. Most distribution transformers change a high voltage primary voltage (12.5 kV or 25 kV) to one of Maritime Electric's three standard secondary voltages: 120/240 V single phase, 120/208 V three phase, and 347/600 V three phase.

Some specialized units, known as step downs, provide a smaller, yet still primary, voltage. The majority of step downs at Maritime Electric are used in the 25 kV system to supply electricity at 12.5 kV and vary in purchase year from 1971 to 2015. The Company is working to retire older step downs though voltage conversions or replacements.

Voltage regulators are a form of transformer that automatically maintains line voltages within a narrowly specified range and provides the ability to maintain CSA standard voltages at substations, on long feeders or on feeders with larger than typical loads.

Overhead Switches and Switchgear

This type of DMA allows for opening and closing of current carrying components, which either prevents or allows the flow of electricity. Switches can have different characteristics:

- Gang operated or single phase operated: A gang operated switch, generally a three phase device, allows all three phases of the switch to be opened or closed at once, often from the ground;
- Switchgear: Switchgear is a combination of electrical disconnect switches, fuses or circuit breakers used to control, protect and isolate electrical equipment;
- Load break or non load break: A load break switch allows for the interruption of power flow even when a significant amount of current is flowing;
- Remote controlled or locally operated; and
- Dielectric: The medium used by the switch to interrupt or insulate can vary; however, most use air while others use vacuum.

Protective and System Devices

Aggregated into this DMA group are:

- Reclosers and distribution circuit breakers;
- Capacitors of two types: Fixed (always ‘on’) or switched (only ‘on’ under specific conditions); and
- New system device evaluations: Maritime Electric is constantly evaluating new system devices in an effort to improve system reliability. Currently, fault indicators are being evaluated. Fault indications are devices hung on a distribution line to assist line crews with fault location. Maritime Electric is also evaluating using reclosers to tie two substation distribution systems together for minimizing recovery time in case of an outage. The “tie reclosers” are connected to Maritime Electric’s communication network and therefore are visible to, and can be controlled by ECC operators.

Revenue Metering and Metering Tanks (CT’s/PT’s)

This item includes:

- Revenue meters that measure, store and report electricity usage;
- Primary (polemounted) instrument transformers (i.e., metering tanks) which include a combination of CT’s and PT’s; and
- Any communications or data aggregation equipment owned by Maritime Electric used to facilitate the revenue metering process.

4.0 INSPECTION AND MAINTENANCE PROGRAMS

4.1 Inspection and Maintenance (General)

Expenditures on inspection and maintenance programs are an integral aspect of any DAMP and good utility practice. Effectively maintaining existing line and substation equipment is necessary to keep equipment in good working condition, maximize equipment lifespan, and improve reliability by reducing the probability of failure. Maintenance programs optimize the value of capital investments. Maintaining equipment in proper working condition reduces the probability of equipment failure, enhances safety and increases reliability of supply to customers.

Maintenance activities at Maritime Electric are performed with a combination of internal personnel and qualified outside contractors and consultants. Inspection and maintenance activities can be subdivided into four basic categories:

Predictive Maintenance:

This is the identification of equipment deficiencies that may lead to failure. Examples of predictive maintenance activities are visual inspections, equipment testing, and substation transformer dissolved gas analysis. Thorough inspection is the primary mechanism used at Maritime Electric for predictive maintenance, although other methodologies are used, such as pole condition testing.

Corrective Maintenance:

This is the repair of equipment as a result of deficiencies identified through visual inspections or testing.

Preventive Maintenance:

Preventative maintenance is the routine servicing or repair of equipment on a regular schedule to ensure that equipment remains in good working condition. Preventative maintenance is undertaken at specific time intervals and is applied regardless of equipment condition. Examples of preventive maintenance activities are vegetation management, switch maintenance, protective device maintenance, and substation equipment maintenance.

Certification Maintenance:

Certain assets require periodic certification or recertification. This generally involves testing, calibration, and documentation (such as a ‘seal’ or ‘sticker’) by a third party accredited or industry accepted expert group, or by Maritime Electric personnel. Examples of managed assets requiring certification:

- Revenue meters and instrument transformers (residential, commercial/industrial, and bulk);
- Insulated booms on bucket trucks;
- Working grounds used by power line workers;
- Lifting capacity of material handler trucks; and
- Rubber cover up and rubber gloves.

Maritime Electric Equipment Maintenance and Asset Replacement Program:

The following guideline is used to aid with the goals and objectives of a formal equipment maintenance and asset replacement program. The following equipment maintenance guidelines are used to determine what level of maintenance is required:

a. Maintenance I: Procedures performed in the shop on new equipment.
b. Maintenance II: A detailed inspection consisting of diagnostic tests to determine if the equipment is functioning adequately. Some equipment does not require overhauls.
c. Maintenance III: Procedures performed at the end of a maintenance cycle as outlined below or as a result of a fault detected during inspections. The objective is to overhaul the equipment and prepare for another maintenance cycle.
d. Maintenance IV: Procedures performed during an unscheduled maintenance activity due to equipment malfunction. Where the malfunction had or could have caused an outage, a limited amount of maintenance will be done if the equipment cannot be taken out of service or there is no spare. If the option to use a spare is available, then Maintenance II will be performed on that equipment.

Table 2 Distribution Equipment Maintenance Cycles			
Equipment	**Visual Inspection Cycle (Maintenance I)**	**Electrical Testing Cycle (Maintenance II)**	**Scheduled Overhaul (Maintenance III)**
Underground			
Underground Vaults	1 year	N/A	NA
Underground Cables and Accessories	5 years	10 years (Hi-pot)	NA
Switches			
Padmount and Metal Clad Switchgears	N/A	5 years	10 years
Transformers			
Substation Transformers	2 month	10 years	10 years
Transformer Oil Sampling	NA	1 year (Analysis-DGA, color, dielectric, etc.)	NA
Voltage Regulators	3 month	5 years (Substation) 7 years (Feeder)	5 years (Substation) 7 years (Feeder) or 150,000 operations
Substation and Feeder Equipment			
Metering Tanks	2 month	10 years	10 years
Reclosers	3 month	5 years (Substation) 7 years (Feeder)	5 years (Substation) 7 years (Feeder) or 200 fault operations
Substation Equipment Oil Sampling	NA	5 years (Dielectric)	NA
Capacitors (with controllers)	1 month	5 years	5 years
Substation Miscellaneous Equipment (i.e., structures, buswork, insulators, lightning arresters, yard lighting, foundations, grounding, control cables, building, yard, station service)	2 month (thermoscan annually)	N/A	N/A

Equipment maintenance report forms are used to record information and data based on the equipment maintenance guidelines.

Equipment installation forms are used to record information on settings, location of equipment, installation checks, and all other necessary data required to update Maritime Electric's equipment database.

4.2 Line Maintenance Activities (General)

Maritime Electric establishes its various line maintenance cycles to achieve a number of objectives:

- Coordinating inspections;
- Inspecting critical assets more frequently and making use of more sophisticated inspection methods (e.g., thermographic scans at substations or in vaults or pole testing);
- Scheduling preventative maintenance activities on cycles that attempt to optimize the life cycle costs of equipment considering the equipment manufacturer's recommendations, good utility practice as well as Maritime Electric past experience;
- Scheduling preventive maintenance activities with cycles greater than one year in a way that levels expenditures from year to year; and
- To the extent possible, scheduling preventive maintenance activities with cycles greater than one year in a way that levels the amount of work assigned to each service centre from year to year. This ensures adequate resource availability to complete the planned program and minimizes travel costs associated with crews traveling between service centers.

The major types of line maintenance activity are described as follows:

<u>Predictive Maintenance</u>

Predictive maintenance on overhead and underground distribution systems generally takes the form of visual inspections and equipment testing.

In 2017, Maritime Electric initiated a Distribution Inspection Program as 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 inspections assess and document any deficiencies found with distribution assets such as poles, cross arms, guy wires, conductors and cables, insulators, arrestors, polemount transformers and switching devices (fused cutouts, load break and disconnect switches, etc.). Padmount transformers and civil facilities, such as transformer pads and cable conduits are inspected more frequently, on a three-year cycle. Assets such as reclosers, voltage regulators, and capacitor banks installed on poles are inspected every three months. Thermographic scans of critical distribution line components and transformers (in vaults or above ground in transformer rooms) are conducted on an annual basis. Deficiencies observed through the Distribution Inspection Program are recorded and prioritized for correction action.

The Company has a Field Asset Maintenance System ("FAMS") where all maintenance items identified through inspections are recorded for future assignment to Maritime Electric field staff. Maintenance items reported by customers are also collected and stored for assignment through the FAMS.

The maintenance items in FAMS are assessed on the basis of the potential for failure and consequential impact on safety or reliability. They are then prioritized for corrective action as follows:

- Major deficiencies, where repair or replacement is required to address a pending failure or safety hazard. Examples of major deficiencies would be broken poles and cross arms; and
- Minor deficiencies, where the deficiency is of a nature where action can be deferred for a time. An example would be a blown lightning arrestor. Repairs to less critical deficiencies are typically planned so that a group of deficiencies within a given area can be addressed by a single crew in a short timeframe.

<u>Corrective Maintenance</u>

Any deficiencies identified through unscheduled inspections are also recorded and prioritized as described above. Repairs or replacements are carried out accordingly and completion is tracked.

<u>Preventive Maintenance</u>

Three major preventive maintenance activities are conducted on distribution lines and equipment:

Vegetation Management

Maritime Electric's Vegetation Management Program is moving towards achieving a seven year cycle, which is believed to be necessary with regrowth rates experienced in recent history. In some areas, limbs and foliage are trimmed back to achieve separation from energized components in a manner that generally allows for good reliability with regrowth between control cycles. In other areas, ground cutting is used to clear the corridor with the line assets, to allow for longer periods between vegetation control efforts. Ground cutting is more cost effective over the long term.

Spot trimming or branch removal in any specific areas where faster than typical growth has occurred, or where one or more damaged branches have entered the minimum clearance zone from outside the vegetation control space, is done on an as needed basis.

Switch Maintenance

Maritime Electric has a formal Switch Maintenance Program for high voltage 69 kV and 138 kV gang operated switches. It does not, however, currently have a formal inspection and maintenance cycle for medium voltage distribution gang operated switches in the distribution system.

Protective Device and Voltage Regulator Maintenance

Maritime Electric performs routine inspection and maintenance of its reclosers and voltage regulators. Maintenance activities are typically performed on a five year cycle for substation reclosers and voltage regulators and a seven year cycle for distribution line reclosers and voltage regulators, and include the following main activities:

- Determination of number of operations since the date of last maintenance, to verify that existing maintenance intervals are adequate;
- Visual inspection of tanks, bushings, contacts, operating mechanisms, control boxes, etc., to identify any broken or deteriorated parts and evidence of surface tracking or corrosion;
- Testing of operations, both manually and using electrical test equipment to ensure proper operation; and
- Electrical testing (ratio, resistance, etc.) to verify electrical integrity of device and all components.

The results of any tests performed are documented on equipment test forms and kept on file for trending and comparison purposes.

4.3 Distribution Substation Maintenance Activities (General)

Predictive Maintenance

Predictive substation maintenance is integral to maintaining reliability and detecting potential equipment failure. Since substation equipment typically requires large investments for installation and since failure of substation components can affect large numbers of customers, detecting potential failures before they occur is very important. As described below, there are presently three key predictive maintenance activities conducted in Maritime Electric substations, with equipment specific methodologies provided in Section 4.4:

Visual Inspections

Visual inspections are essential for assessing the condition of substation components and identifying deterioration or areas where attention is required. Maritime Electric typically conducts detailed visual inspections on each of its distribution substations once every two months.

Substation buildings, fences, and electrical components (buswork, switches, insulators, transformers, ground conductors, reclosers, metering tanks, voltage regulators, etc.) are inspected and any deficiencies recorded. In addition, data such as relay targets, breaker counters, direct current system voltage, and substation transformer gauge readings are recorded. The condition of ancillary equipment such as lighting, eyewash stations, first aid kits, and oil spill kits is also inspected. During these bi-monthly inspections, the remainder of the substation is visually inspected at a high level and deficiencies requiring immediate correction are identified. Any deficiencies noted during inspections are recorded, reported, and are then prioritized for corrective action.

Transformer Dissolved Gas Analysis

Dissolved Gas Analysis (“DGA”) is an effective tool for assessing the condition of substation power transformers and identifying deterioration in substation transformer oil or insulation. DGA can also identify whether arcing or acid build up is occurring inside the transformer. DGA tests for the presence of dissolved gas and water in transformer insulating oil, and based on the level of gas(es) or moisture present; assess the condition of the transformer. An important aspect of DGA is the trend analysis, which reviews the history of dissolved gas levels in the transformer.

DGA is performed annually on all transformers in Maritime Electric substations, whether in service or spare. Maritime Electric uses qualified personnel to perform the analysis, provide reports on transformer condition, and recommend any required actions if gassing is above normal levels or if acids are detected. Corrective action to deal with abnormalities is essential to prevent failure and extend the life of the transformer.

Thermographic Scanning

Thermographic (infra-red) scanning is scheduled annually for all distribution substations. Thermography captures the temperature of components compared to surrounding equipment and ambient temperature, and high relative temperatures can be indicative of overloaded or deteriorated components.

<u>Corrective Maintenance</u>

Corrective maintenance is a reactive activity that takes place when deficiencies in substation components are identified. Defective components are prioritized for repair or replacement on the basis of the severity of the condition, the criticality of the equipment, and the potential impact of failure on safety or service reliability.

<u>Preventive Maintenance</u>

Preventive maintenance on substation components is conducted on a regular basis and is integral to keeping equipment in good working condition. Substation components typically undergo preventive maintenance on a five year cycle, including inspecting, cleaning, lubricating, and testing. The major activities described below are included in this program, with specific equipment methodologies provided in Section 4.4.

- <u>Transformers (Distribution and Instrument):</u> Inspection and cleaning, DGA, Doble testing, on-line tap changer maintenance (including oil refurbishment and contact inspection and replacement as required), and inspection and cleaning of gauges, access ways, bushings and connections;

- Recloser Maintenance: Inspection, cleaning of bushings, connections, contacts and moving parts, contact resistance and insulation testing;
- Switch Maintenance: Inspection and cleaning of bushings, connections, contacts, arc horns, and operating mechanisms and insulation testing;
- Oil Renewal: Replacing insulating oil in substation transformers, and oil insulated circuit breakers and potential transformers as needed, to ensure insulating oil is clear of contaminants; and
- Accessories: Other equipment such as motor operators and heating elements are inspected, cleaned, and maintained.

4.4 Substation Equipment Maintenance Methodologies (Type Specific)

Predictive Maintenance Methodologies:

Predictive maintenance methodologies for specific types of substation equipment are as follows:

Overhead Switches

- Inspect the insulators for breaks, cracks, burns, or cement deterioration. If necessary, clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important to minimize the possibility of flashover as a result of the accumulation of foreign substances on the insulator surfaces;
- Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona;
- Check cutouts for damaged fuses and replace if necessary; and
- Scan the switch with an infrared scanner to check for further defects.

Underground Switches and Junction Units

- Scan the switch with an infrared scanner to check for defects.

Surge Arrestors

- Check for cracked, contaminated, or broken porcelain; loose connections to line or ground terminals; and corrosion on the cap or base; and
- Check for pitted or blackened exhaust parts or other evidence of pressure relief.

Buses and Shield Wire

- Inspect bus supports for damaged porcelain and loose bolts, clamps, or connections;
- Observe the condition of flexible buses and shield wires; and
- Inspect suspension insulators for damaged porcelain (include line entrances).

Structures

- Inspect all structures for loose or missing bolts and nuts;
- Observe any damaged paint for galvanizing or signs of corrosion; and
- Inspect for deterioration, buckling, and cracking.

Grounding System

- Check all above grade ground connections at equipment, structures, fences, etc.; and
- Observe the condition of any flexible braid type connections.

Control and Metering Equipment

- Check current and potential transformers for damage to cases, bushings, terminals, and fuses;
- Verify the integrity of the connections, both primary and secondary;
- Observe the condition of control, transfer, and other switch contacts; indicating lamps; test blocks; and other devices located in or on control cabinets, panels, switchgear, etc. Look for signs of condensation in these locations;
- Examine meters and instruments externally to check for loose connections and damage to cases and covers. Note whether the instruments are reading or registering;
- Open and close each potential switch on the test block to determine whether the speed of the meter disk changes. Repeat the process with the current switches. Changes of speed should be approximately the same for each meter element;
- Check the status of relay targets (where applicable);
- Make an external examination of relays, looking for damaged cases and covers or loose connections;
- Check the station battery for loose connections and battery cells for low level or low specific gravity of the electrolyte. Record the electrolyte temperature;

- Inspect the station battery charger. Check the charging current and voltage. Observe the ground detector lamps for an indication of an undesirable ground on the direct current ("DC") system; and
- Check the annunciator panel lights.

Metal Clad Switchgear

- Inspect for damage to enclosures, doors, latching mechanisms, etc.;
- Inspect bus supports for signs of cracking;
- Verify that all joints are tight;
- Check the alignment of all disconnect devices, both primary and secondary, including those for potential transformers;
- Inspect terminal connections and the condition of wiring;
- Check rails, guides, rollers, and the shutter mechanism;
- Inspect cell interlocks, cell switches, and auxiliary contacts;
- Inspect control, instrument, and transfer switches; and
- Inspect for broken instrument and relay cases, cover glass, etc., and check for burned out indicating lamps.

Cables

- Inspect exposed sections of cable for physical damage;
- Inspect the insulation or jacket for signs of deterioration;
- Check for cable displacement or movement;
- Check for loose connections; and
- Inspect shield grounding (where applicable), cable support, and termination.

Foundations

- Inspect for signs of settlement, cracks, spalling, honeycombing, exposed reinforcing steel, and anchor bolt corrosion.

Substation Area General

- Verify the existence of appropriate danger and informational warning signs;
- Check indoor and outdoor lighting systems for burned out lamps or other component failures;
- Verify that there is an adequate supply of spare parts and fuses;

- Observe the condition of hook sticks;
- Inspect the fire protection system and the provisions for drainage in the event of leaking oil;
- Check for bird nests or other foreign materials in the vicinity of energized equipment, buses, or fans;
- Observe the general condition of the substation yard, noting the overall cleanliness and the existence of low spots that may have developed;
- Observe the position of all circuit breakers in the auxiliary power system and verify the correctness of this position; and
- Inspect the area for weed growth, trash, and unauthorized equipment storage.

Substation Fence

- Check for minimal gap under the fence or under the gate. Ensure that all gaps are less than 50 mm at any point under the fence and less than 100 mm at any point under the gate;
- Ensure the fence fabric is intact and there is no rust;
- Check that the barbed wire is taut;
- Ensure the gate latches are operable;
- Ensure flexible braid type connections are intact; and
- Verify that no wire fences are tied directly to the substation fence.

Preventive Maintenance Methodologies:

Preventative maintenance methodologies for specific types of substation equipment are as follows:

Inline Switches (Non-Gang Operated)

- Open/Close the switch several times. Periodic operation of the switch is recommended as this ensures the hinge pivot point is operating smoothly and helps clean any oxide from the jaw contacts, which may have formed since the last maintenance;
- Check for simultaneous closing of all blades and for proper seating in the closed position;

- Check the switch for alignment, contact pressure, eroded contacts, corrosion, and mechanical malfunction;
- Inspect the insulators for breaks, cracks, burns, or cement deterioration. If necessary clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important to minimize the possibility of flashover as a result of the accumulation of foreign substances on the insulator surfaces;
- Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona;
- Where the switch blade has been left open for an extended period of time, if necessary, the jaw and blade contacts should be wiped clean of any dirt particles to ensure that there will be no plating damage to the contacts and that they will properly mate. If necessary, thinners or acetone may be used to clean the contacts and if the contacts are heavily coated use a fine Scotch-Brite® pad;
- Scan the switch with an infrared scanner to check for further defects; and
- In addition to the above, perform the switch maintenance that is specified in the Maritime Electric maintenance report.

Gang Operated Switches

- The switch should be disconnected from all electric power sources before servicing;
- Ground leads or their equivalent should be attached to both sides of the switch;
- Inspect the insulators for breaks, cracks, burns, or cement deterioration. Clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important to minimize the possibility of flashover as a result of the accumulation of foreign substances on the insulator surfaces;
- Check the switch for alignment, contact pressure, eroded contacts, corrosion, and mechanical malfunction. Replace damaged or badly eroded components. If contact pitting is of a minor nature, smooth the surface with clean, fine sandpaper (not emery) or as the manufacturer recommends. If recommended by the manufacturer, lubricate the contacts;
- Inspect arcing horns for signs of excessive arc damage and replace if necessary;

- For all S&C Alduti-Rupter brand switches, perform the outlined continuity check and additional maintenance as outlined in the Alduti-Rupter Switch, General Maintenance Outline;
- Check the blade lock or latch for adjustment;
- Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona. Check corona balls and rings for damage that could impair their effectiveness;
- Inspect inter-phase linkages, operating rods, levers, bearings, etc., to assure that adjustments are correct, all joints are tight, and pipes are not bent. Clean and lubricate the switch parts only when recommended by the manufacturer. Check for simultaneous closing of all blades and for proper seating in the closed position. Check gear boxes for moisture that could cause damage due to corrosion or ice formation. Inspect the flexible braids or slip ring contacts used for grounding the operating handle. Replace braids showing signs of corrosion, wear, or having broken strands;
- Power operating mechanisms for switches are usually of the motor driven, spring, hydraulic, or pneumatic type. The particular manufacturer's instructions for each mechanism should be followed. Check the limit switch adjustment and associated relay equipment for poor contacts, burned out coils, adequacy of supply voltage, and any other conditions that might prevent the proper functioning of the complete switch assembly;
- Inspect overall switch and working condition of operating mechanism. Check that the bolts, nuts, washers, cotter pins, and terminal connectors are in place and in good condition. Replace items showing excessive wear or corrosion. Inspect all bus cable connections for signs of overheating or looseness; and
- Inspect and check all safety interlocks while testing for proper operation.

Substation Transformers

- Inspect the control cabinet, control relays, contactors, indicators, and the operating mechanism;
- Look for loose, contaminated, or damaged bushings; loose terminals; and oil leaks;
- Check oil levels in main tanks, tap changer compartment, and bushings;
- Inspect the inert gas system (when applicable) for leakage, proper pressure, etc.;

- Read and record the operations counter indicator reading associated with the load tap changer;
- Observe oil temperature. Oil temperature should not exceed the sum of the maximum winding temperature as stated on the nameplate plus the ambient temperature (not to exceed 40 degrees Celsius [ºC]) plus 10ºC. Generally, oil temperature does not exceed 95ºC and 105ºC for 55ºC and 65ºC winding temperature rise units, respectively; since the ambient temperature rarely exceeds 30ºC for periods long enough to cause an oil temperature rise above these points;
- Perform the power factor test;
- Perform the turns ratio test;
- Perform the winding resistance test;
- Perform the excitation current test;
- Perform the insulation resistance test;
- Send sample to lab for DGA; and
- In addition to the above perform the transformer maintenance that is specified in the Maritime Electric maintenance report.

4.5 Revenue Metering and Instrument Transformer Maintenance

Revenue metering and instrument transformer assets require certification maintenance in addition to the typical ‘physical’ maintenance (predictive, corrective, and preventative) required by most other types of DMA. Typically, each class of revenue meter and instrument transformer (current transformers and potential/voltage transformers) must be recertified by an accredited testing organization on a recurring basis.

The frequency and nature of these recertifications are dictated by regulations enforced by Measurement Canada (Industry Canada), a Federal Government regulator. In the past, these regulations have allowed for sample testing and ‘family’ testing of entire groups of revenue meters rather than full testing of each and every individual meter. Whatever method is used to recertify a group of meters, meticulous and detailed records must be maintained for every individual meter and retained throughout the life of the meter.

5.0 SYSTEM PERFORMANCE AND RELIABILITY

5.1 General

Maritime Electric does not rely solely on regulation as the impetus to maintain a high level of service and believes that meeting customer expectations for system performance is part of its mission as a corporation. As part of managing system performance, Maritime Electric prepares reports on a monthly, quarterly, and annual basis for all service quality indicators.

Maritime Electric monitors system performance metrics to determine what trends, if any, are developing. The reliability indicators assist in developing the programs within the DAMP through root cause analysis. Capital investments made over the past few years are yielding favourable results, as reliability has improved. Significant work has taken place in specific areas where the infrastructure was visibly aging, or where trend analysis indicated deficiencies.

5.2 Reliability Analysis

A key objective of the DAMP is to maintain a high level of distribution system reliability. Capital investments are aimed at improving or maintaining reliability by proactively upgrading deteriorating facilities and adding system capacity to avoid overloads. Investments are also made to ensure that sufficient system redundancy exists so that customers can be supplied from alternate paths in emergency or planned outage situations. Investments in technology such as supervisory control and data acquisition ("SCADA") provides real time system information that facilitates the rapid identification of system problems and remote switching to improve the efficiency of outage response.

In addition to the capital investments, maintenance programs and operational practices are also aimed at reliability. For example, in its service territories Maritime Electric maintains systematic vegetation management programs to maintain clearances between power lines and surrounding vegetation. In forced outage situations, outage response efforts focus on locating and isolated faulted areas promptly so that most affected customers can be restored from alternate paths. When system components must be taken out of service for planned maintenance, switching is carried out so as to minimize disruption to customers.

The application of SCADA technology allied to control room oversight is a key component of Maritime Electric operations, and also impacts reliability performance. Maritime Electric's Energy Control Centre ("ECC") is currently staffed on a 7 day/24 hour basis. The ECC provides efficient identification of system problems during normal workdays and after hours, which is an essential component of effective outage response.

Maritime Electric maintains databases of all outages that occur on its distribution system. This allows for the tracking and analysis of reliability performance. The two key indices are defined by CEA as follows:

- *System Average Interruption Duration Index* ("SAIDI") – reflects the total outage time to the average customer over a period of one year.
- *System Average Interruption Frequency Index* ("SAIFI") – reflects the number of interruptions to the average customer over a one year period.

Indices are computed on a monthly and annual basis. Data is submitted to IRAC in accordance with regulatory requirements. In addition, data is also analysed internally by Maritime Electric to identify reliability trends and potential areas for reliability improvement.

As an example of the data produced, SAIDI and SAIFI reliability indices for Maritime Electric's transmission and distribution over the five year time period 2016 to 2020 are shown in the following table:

Table 3
Maritime Electric CEA Reliability Indices for Years 2016 to 2020

Year	2016	2017	2018[2]	2019[3]	2020
SAIDI (hours)	11.13	3.96	23.83	40.19	4.98
SAIFI	3.69	2.61	6.75	5.50	2.19

2 November 29, 2018 – snow, ice and wind storm.
3 September 7, 2019 – post-tropical storm Dorian.

IEEE 2.5 Beta Method

An Institute of Electrical and Electronics Engineers ("IEEE") working group has developed a statistical approach to the problem to define a Major Event Day ("MED"). Their recommendation, known as the 2.5 Beta Method, works as follows:

- A MED is any day that exceeds a daily SAIDI threshold called the Major Event Threshold ("T_{MED}");
- Daily SAIDI values for the past five years are used to calculate T_{MED};
- The natural log ($\log_e$) of each SAIDI value is calculated and the $\log_e$-average (α) is calculated; and
- The standard deviation of the natural logarithms is calculated (β). Using an Excel spreadsheet and the standard deviation function ("STDEV") the $\log_e$-standard deviation is calculated.

From this data, T_{MED} is,

$$\mathbf{T_{MED} = \boldsymbol{e}^{(\alpha + 2.5 * \beta)}}$$

Where,

T_{MED} = Major Event Threshold, minutes

e = Euler's number, 2.718

α = Log_e-average of the data

β = Log_e-standard deviation of the data

Below is a comparison between SAIDI (CEA) and SAIDI (IEEE MED Excluded).

Table 4
Comparison of SAIDI (CEA) and SAIDI (IEEE MED excluded)

Year	SAIDI (CEA)	SAIDI (IEEE MED Excluded)
2016	11.13	2.46
2017	3.96	2.25
2018	23.83	3.25
2019	40.19	2.98
2020	4.98	2.57

One of the reasons to factor out major events is to normalize the SAIDI information. This helps to ensure that the utility is responding to real changes in its reliability indices and is not chasing variances caused by major events such as hurricanes, ice/sleet, storms and other such disturbances. Understanding how to correctly apply the IEEE standard reliability indices is the first step in measuring the reliability of an electric utility's distribution system. Major events are removed from the base data so that reliability measures are not distorted and to help the utility track improvements to the electric system.

6.0 DISTRIBUTION PLANNING

Prudent and timely planning lies at the core of any sustainable asset management program. At Maritime Electric, planning is a continuous and evolving process designed to meet the present and changing needs of a variety of stakeholders. This is accomplished through the general categories of planning described below, with ongoing interaction between all three types:

6.1 Long Term Planning (Forecast Horizon Typically 10 Years)

Long range distribution planning is generally performed through the preparation and periodic review of long term system planning studies for the organization. System planning studies analyze the existing transmission and distribution systems and anticipated customer load and generation changes over a planning horizon of 10 years. While system planning studies separately analyze the existing transmission and distribution systems, neither is done in isolation of the other given the interdependency of transmission on distribution and vice versa.

A long-term load (and generation) forecast is prepared, using the best information available at the time of the study. The load forecast is based on an econometric model using inputs such as load, number of customers, population growth, gross domestic product ("GDP") and consumer price index ("CPI"). The Company compiles future economic projections for the Island and incorporates these into the regression analysis.

Technical issues like component capacities, ability to operate within voltage requirements, and basic contingency analysis are reviewed, and system deficiencies (present and predicted through the load forecast period) are identified. Various alternatives and solutions are proposed and then analysed to ensure that they address all predicted deficiencies.

Maritime Electric is monitoring the adoption of electric vehicles ("EV's") on PEI. In 2020 Maritime Electric purchased an electric vehicle to operate within its fleet. This project will allow the Company to evaluate an electric vehicle in terms of operating and maintenance costs, practicalities of use, and overall value.

Widespread EV (either plug in hybrid or battery electric) adoption on PEI will require upgrades to various distribution system components including, but not limited to, protection devices, line and service conductor, distribution and substation transformers, and power quality equipment. Currently early adoption on PEI is low (under 100 EV's); however, as more EV's are purchased/imported to the Island, Maritime Electric will continue to monitor the impact to the grid and determine where and when upgrades are required. More details on the transmission and supply requirements of EV's can be found in the Company's Integrated System Plan ("ISP").

Generally, a complete long term system planning study for Maritime Electric will be performed at regular intervals of several years, with periodic reviews to ensure that the information and conclusions in each study are still reasonably accurate and valid as more recent data becomes available.

6.2 Medium Term Planning (Five Year Planning Horizon)

Maritime Electric uses results from its strategic planning and other reports, such as asset condition reports, to perform 'tactical' planning which covers a five-year period. Changes to the regulatory environment must be taken into account as well.

Medium term planning is performed each year, to incorporate new information that may arise, such as new regulations, increased load growth, longer term individual customer needs or updated asset condition reports. Typical inputs to medium term planning include:

- Customer driven needs;
- Municipal driven needs;
- Regulatory requirements;
- Reliability analysis;
- Asset evaluation and renewal requirements;
- Expansion requirements identified through long term planning; and
- Extraordinary initiatives, such as the electrification of transportation.

The results of this medium term planning set priorities, goals and targets to define optimal and sustainable levels of activity in all areas. The outcomes of tactical planning contribute directly to the corporate five year fiscal plan.

Heat pumps have become popular in recent years in addition to the increase in the percentage of customers using electric resistance heating as their primary source of heat. Heat pumps are being installed mainly by residential customers and some general service customers looking to displace a portion of their furnace oil usage with the added benefit of having air conditioning available in the summer. The shift to heat pumps has resulted in an increased peak load for both winter and summer.

In order to supply new load and decrease losses, a new 138/25 kV Clyde River Substation is being constructed. The new substation at Clyde River will serve load growth in residential and general service load in the area. Also, in the short term, a new substation at East Royalty will replace the aging Scotchfort Substation and serve residential growth in the area, which includes York and Suffolk. In the long term, Scotchfort Substation will be rebuilt and fed at 138 kV. Maritime Electric has identified the need for a new distribution substation in the Tignish area in the near future. A long term identification of needs is provided in the ISP, including information on Cavendish, Crapaud, Mount Pleasant, and Bedeque areas. In other areas, additional feeders may also be required to accommodate growth and decrease losses. The plan for these new substations and associated feeders is based on a projected residential and general service load growth that takes in consideration residential and general service electric heat load increase experienced in the last few years plus any additional industrial loads. Maritime Electric continuously monitors the load growth and adjust its plan depending on the pace and location of the load growth.

Maritime Electric is planning to replace a distribution substation power transformer each year for the next five years. These replacements are due to load growth and age/reliability and the first is scheduled for Rattenbury in 2021. The substations receiving a new transformer in 2022 and beyond will be determined based on load growth and age/reliability.

6.3 Short Term Planning (One Year Planning Horizon)

Short term or operational planning involves detailing the tasks required to complete current year projects as well as operate the distribution system in a safe and reliable manner. It also addresses short term needs, such as connection of a customer or development that was not identified previously during medium term planning, or reaction to external events such as a severe ice storm.

7.0 ASSESSMENT OF ASSET CONDITION

7.1 Distribution Substations

The nature of distribution substation equipment does not lend itself to purely quantitative evaluation of its condition. In addition, the relatively low quantity of each type of substation asset ensures that each item can receive regular inspection, maintenance, and qualitative assessment. Since each piece of substation equipment is also relatively expensive to replace, it is generally cost effective to perform regular maintenance on it rather than relying on run to failure techniques which make more sense for low value items like line insulators or cross arms. The following sections provide a summary of the condition of Maritime Electric's distribution substation equipment:

7.2 Poles

A wooden utility pole generally remains useful until:

- It fails (breaks or collapses) due to severe weather, vehicle impact, or loss of strength associated with advanced aging;
- New requirements necessitate a pole change out. These needs might be for a taller or stronger pole to support more equipment;
- The pole is no longer required at its legacy location; and
- Though a gradual process of loss of wood fibre and loss of fibre strength, the strength of the pole decreases until it reaches the point where it no longer satisfies required safety factors under worst case conditions. At this point, inspections and/or testing will identify the need to replace this pole.

Like many other types of distribution assets, distribution poles are expected to last for a long time. A service life of 50 years is expected and when used under typical conditions, the maintenance free Mean Time Between Failures (“MTBF”) is in the order of 400,000 hours.

It should be noted that the actual mean service life of utility poles is usually less than 50 years, as many are removed or upgraded due to such factors as road realignments or a need to upgrade to a taller or stronger pole as part of a distribution line upgrade.

Individually, the replacement value of these assets range from $1,000 to over $15,000. Maritime Electric has roughly 145,000 poles in service.

Because of the high MTBF value, relatively low installed cost, and large installed base of poles, it would be extremely impractical or impossible to closely monitor and maintain each pole in the same fashion as a substation steel structure, and the expense of such a program would far exceed its utility.

Instead, Maritime Electric manages its pole assets through a combination of:

- Industry standard purchasing specifications;

- Review of manufacturer's' quality assurance ("QA") and quality control ("QC") efforts;
- Inspection of new distribution poles as they are received;
- Periodic inspection and testing of poles while they are retained in stores as spares;
- In-situ inspections and periodic testing of poles whenever they are installed and/or visited during fieldwork; and
- Intake inspection whenever a previously used pole is returned to storage from the field. Occasionally, a pole in near perfect condition is reissued to the field.

7.3 Distribution Transformers

Defining Asset Condition

Like many other types of distribution assets, distribution transformers are expected to last for 40 years under typical conditions. The maintenance free MTBF of a distribution transformer is in the order of 300,000 hours. Individually, the replacement value of these assets range from $2,000 to over $53,000. Maritime Electric has roughly 38,000 in-service transformers.

Because of the high MTBF value, relatively low cost, and large installed base of distribution transformers, it would be extremely impractical or impossible to closely monitor and maintain each transformer in the same fashion as a substation power transformer, and the expense of such a program would far exceed its utility.

Instead, Maritime Electric manages its distribution transformer assets through a combination of:

- Industry standard purchasing specifications;
- Review of manufacturer's QA and QC efforts;
- Examination of the manufacturer's technical drawings and data for each distribution transformer order placed;
- Inspection and testing of new distribution transformer as they are received;
- Periodic inspection and technical testing of distribution transformers while they are retained in Maritime Electric's Stores department as spares;

- In-situ inspections and monitoring of transformers whenever they are installed and/or visited during fieldwork;
- Inspection whenever a previously used distribution transformer is returned to storage from the field. This is particularly important if the distribution transformer was removed from service because it is suspected to be not in good working order; and
- Exceptional programs may be initiated if an unforeseen issue arises. For example, the entire Maritime Electric inventory was tested for Polychlorinated Biphenyl (PCB) content in the mid-1980's once concerns were raised about environmental issues associated with these chemicals.

Maritime Electric has transitioned to using more efficient amorphous core transformers for polemount and padmount units. There are two types of losses associated with each transformer in the system; no-load losses and load losses. The no-load loss on a transformer is the energy used to keep the transformer energized with little or no load and the load loss is the energy required when the transformer is under load. Typically, a transformer is not fully loaded 100 per cent of the time so both of these factors affect the amount of energy required to operate a transformer. The amorphous core transformers have a core made of amorphous metal which significantly reduces the no-load losses. With this improved efficiency, the system's power factor will improve and less current flow is required to energize the transformer resulting in lower demand and energy costs. Amorphous core transformers are more expensive than traditional crystalline core transformers; however, the increased cost is more than offset by the savings received from lower system losses over the life of the transformer.

<u>In-Situ Testing of Pre-1982 Distribution Transformers for PCB</u>

In 2019, Maritime Electric engaged Emera Utility Services ("EUS") to carry out live testing of in-service polemount transformers what were manufactured prior to 1982 ("pre-1982"), to determine if the transformer oil contained PCB compounds.

The testing was required for Maritime Electric to be able to ensure that all equipment with PCB concentrations equal to or greater than 50 parts per million ("PPM" or "mg/kg") is removed from service before December 31, 2025, as required by Federal regulation.

In total, 2,571 pre-1982 polemount transformers were tested by EUS with the results provided in Table 5 below.

Table 5 Pre-1982 Transformer In-Situ PCB Testing Results		
PCB In-Situ Live Transformer Sample Results	**Count**	**Percentage**
<2 mg/kg PCB	2135	83%
≥2 to <50 mg/kg PCB	340	13%
≥50mg/kg PCB	46	2%
Transformers Retired	50	2%
Total	**2571**	**100%**

Upon completion of the sampling and testing program, all of the pre-1982 polemount transformers with a PCB concentration greater than 50mg/kg were removed from service and sent to an approved PCB disposal site. Some of the larger transformers with PCB concentrations less than 50mg/kg were also retired.

7.4 Other Distribution Assets

For other types of distribution assets, Maritime Electric uses good utility practice to anticipate when they are nearing the end of their useful life and endeavors to replace them before they fail.

In the event of a premature or other failure of an asset or asset component, Maritime Electric uses well established and industry-typical emergency response procedures to replace them in a timely and cost effective manner.

8.0 ASSET REPLACEMENT PROGRAM

Maritime Electric uses a variety of tools and methods to develop and monitor the Company’s detailed budgets, which include both capital and operating/maintenance items.

8.1 Recent Historical Replacement Rates

Distribution Transformers

Maritime Electric has approximately 36,800 distribution polemount transformers in service. With an expected transformer life of 40 years, an average replacement rate of 920 transformers/year is required in order to achieve a sustainable average transformer age and condition.

Table 6 below shows the number of distribution polemount transformers replaced in each of the last five years[4].

Table 6
Distribution Polemount Transformers Replaced 2016 to 2020

Year	Transformers Replaced
2016	636
2017	474
2018	867
2019	1,093
2020	575

A program to optimize distribution transformer installations has been developed to reduce the number of transformers installed. The program involves installing a larger sized polemount transformer in locations where successive groups of poles have distribution transformers mounted upon them. The larger polemounts will serve all customers in the area and the multiple smaller transformers will be removed. This program will optimize the number of distribution transformers to be managed and the system capacity of distribution transformers in the field.

Poles

Maritime Electric has approximately 145,000 distribution poles in service with approximately 18,000 being joint use poles owned by Bell Canada. The Company therefore owns approximately 127,000 distribution poles. With an expected distribution

[4] For poletop transformers, asset retirement data was used for estimating annual replacement rates.

pole service life of 50 years, an average replacement rate of 2,540 Company owned poles/year is required in order to achieve a sustainable average pole age and condition.

Table 7 below shows the number of distribution poles replaced in each of the last five years[5].

Table 7 Distribution Poles Replaced 2016 to 2020	
Year	**Poles Replaced**
2016	910
2017	1,710
2018	2,482
2019	3,742
2020	2,442

The vast majority of eastern cedar poles in the Company's distribution system are over 40 years of age. In the past, these poles were being replaced through a combination of rebuild projects and storm events at a combined rate of approximately 900 per year. With the addition of the Eastern Cedar Pole Replacement Program in 2019, the target replacement rate was increased to approximately 1,500 poles per year. This reduced the timeframe for substantial removal of all eastern cedar distribution poles to approximately 10 years. Table 8 shows the number of eastern cedar poles remaining in the distribution system.

Table 8 Eastern Cedar Poles in Maritime Electric Distribution System	
Year End	**Eastern Cedar Poles Remaining**
2018	15,980
2019	12,471[6]
2020	11,020

8.2 Recent Historical and Future Capital Expenditures

Actual gross spending on Maritime Electric's distribution assets over the years 2016 to 2020 is shown in Figure 49 along with forecast spending for the years 2021 to 2025. This includes all spending on items such as replacement of assets due to storms, replacement

5 For distribution poles, asset retirement data was used for estimating annual replacement rates.

6 In addition to the poles replaced through the Eastern Cedar Pole Replacement Program in 2019, inspection identified 2,365 poles that were in the database as eastern cedar to be of a different type; as such, they were removed from the eastern cedar poles remaining count.

of assets due to government transportation infrastructure projects, streetlight work, installation of transformers, new services, installation of distribution equipment, metering tools and equipment, transportation equipment, line upgrades and line extensions. It is noted that these numbers are gross investments and do not show the offsetting effect of customer capital contributions. Examination of this data shows relatively stable capital spending on Maritime Electric's distribution system over the last five years (2016 to 2020). Over the next five years (2021 to 2025), Maritime Electric is adjusting its budget to increase capital spending on the distribution system to ensure targets for sustainable asset renewal can be achieved. The forecast budget increase for the next five years is driven largely by the PEI Broadband Project and a transition to smart meters.

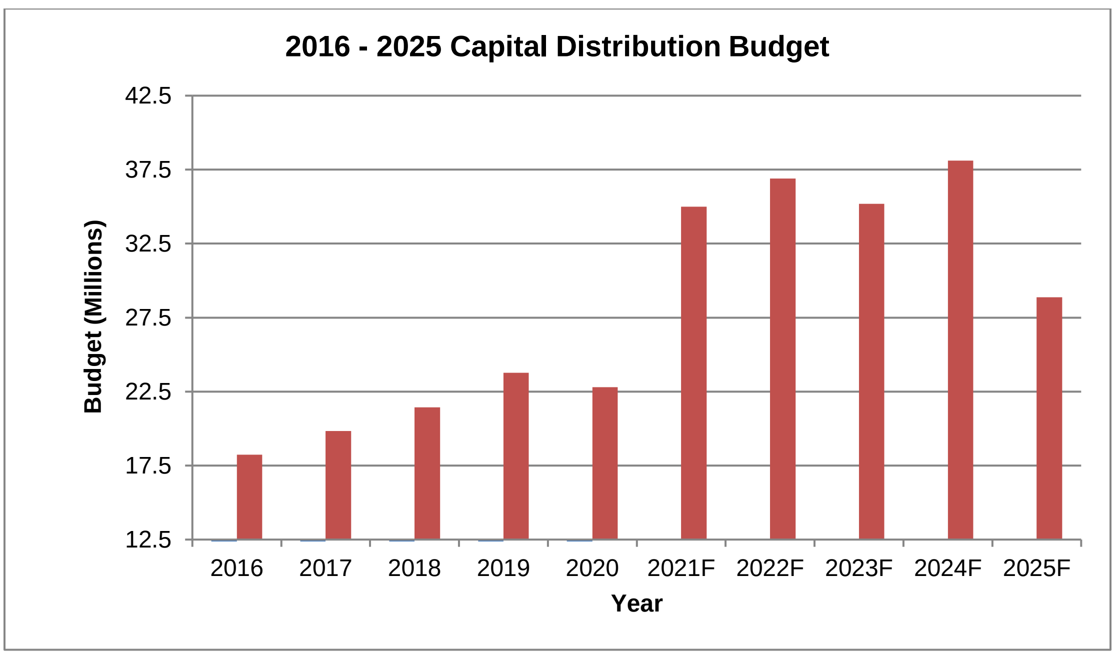


Figure 49: Annual/Forecast Capital Spending on Distribution System 2016 to 2025

8.3 Priorities for Budget Decision Making

The priority for budgeting is to provide a sustainable level of spending and resource deployment throughout the distribution system to accommodate safety improvements, planning for growth, improved system performance and reliability, renewal of deteriorated assets, customer growth needs, short and long term system planning needs and overall asset life cycle costs.

These factors must be continuously balanced while seeking to avoid undesirable customer rate shocks that can be triggered by large changes in annual revenue requirements when capital spending varies considerably from year to year.

Asset Replacement Planning Strategy

In planning for distribution asset replacement, Maritime Electric prioritizes projects as follows:

Priority Projects

Many capital expenditures are considered priority due to the nature and obligations of owning and operating an electric utility. Efforts must be made to ensure that these projects are performed in an efficient, cost effective and sustainable manner, both in the short term and over the long term.

Examples of priority projects include:

- Replacement of damaged transformers;
- Distribution line expansions and enhancements triggered by new customers and customers with increased loads;
- Projects triggered by external regulatory programs;
- Poles struck by vehicles;
- Unanticipated failure of a major substation component; and
- Retirement of PCB contaminated assets.

Non-Priority Projects

Some of the priority projects occur with enough regularity that statistical methods can be applied to roughly predict future expenditures. An example of this would be the capital spending on system expansions associated with the connection of new residential customers. Resources must be set aside in the budget forecast to allow for such projects.

Once the needs of these priority projects are addressed in the budget, non-priority projects are planned with a goal of smoothing out the year to year spending to allow for efficient resource scheduling.

Some expenditures can be deferred for one or more budget years. An example would be the replacement of distribution lines that have been in service for many years and are nearing the end of their useful life.

Note that these non-priority projects can only be deferred in the short term. Some of these may be deferred for one or more years, but will still need to be done sooner rather than later. The need to achieve optimum levels of re-investment has to be balanced against the need to manage the overall risks associated with such deferrals.

Since new non-priority projects will inevitably be identified in the future, it is essential to ensure that sufficient resources are allocated to avoid a long term build up or ‘backlog’ of such projects. This would result in a DAMP that is not achieving its sustainable goals.

When determining the order in which non-priority projects will be scheduled, the following factors will be considered:

- Severity of problem(s) or importance of the need for the project and the impact of project deferral;
- Impact on corporate risk when a project is scheduled/deferred;
- Impact on uncommitted budget (and therefore revenue requirement/future rate stability);
- Impact on future reliability improvements (e.g., a new distribution substation component may benefit more customers than a pole line rebuild, even though they cost the same to replace);
- Stakeholder requirements (e.g., customers, municipalities, regulators, etc.);
- Availability of internal and external resources; and
- Opportunities to achieve economies of scale by performing fewer, larger projects.

8.4 Dynamic Nature of Capital Priority Planning

It should be noted that this is a ‘living or evolving’ document that will be changed and adjusted as new information becomes available to Maritime Electric. It is based on best practices applied to presently known data. As new issues arise and new data becomes available, Maritime Electric expects to review this DAMP on a timely basis and make any necessary adjustments.

Examples of issues which would likely trigger such an adjustment include:

- One or more large industrial customers committing to construction in Maritime Electric’s service territory;
- Large scale customer adoption of new technology, such as electric heat or electric vehicles; and/or
- Large scale solar and wind generation integration.

INTERROGATORIES

IR-2 – Attachment 1

	AMENDED - Appendix A													
	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	$ 1,425,415	$ 1,037,146	$ 1,678,001	$ 6,511,909	$ 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	23,530,797	27,473,849	30,282,427	42,057,240	62,872,000	60,407,000	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	7,854,808	11,600,474	12,362,651	13,054,376	21,095,000	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	1,894,376	2,311,382	3,157,514	4,692,794	12,368,000	10,498,000	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	34,705,396	42,422,851	47,480,593	66,316,319	97,765,000	99,074,000	102,800,000	100,912,000	100,573,000	101,075,000
Capitalized General Expense (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
Interest During Construction (G)	405,915	449,760	432,111	474,433	444,170	548,015	559,997	779,035	1,219,000	2,109,000	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	35,639,311	43,651,909	48,737,207	67,936,876	99,828,000	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)	(1,094,598)	(1,483,088)	(1,346,601)	(1,585,856)	(14,579,000)	(8,550,000)	(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**	**34,544,713**	**42,168,821**	**47,390,606**	**66,351,020**	**85,249,000**	**93,552,000**	**103,437,000**	**100,771,000**	**101,125,000**	**101,814,000**
Capacity Application														
Generating Capacity (K)	-	-	-	-	-	-	-	-	-	9,635,000	17,045,000	46,304,000	100,333,000	162,668,000
Interest During Construction (L)	-	-	-	-	-	-	-	-	-	644,000	1,140,000	3,096,000	6,708,000	10,876,000
	-	-	-	-	-	-	-	-	-	10,279,000	18,185,000	49,400,000	107,041,000	173,544,000
Solar Application														
Solar Facilities	-	-	-	-	-	-	-	-	-	18,337,000	16,846,000	8,346,000	6,769,000	-
Interest During Construction (L)	-	-	-	-	-	-	-	-	-	1,226,000	2,353,000	2,911,000	-	-
	-	-	-	-	-	-	-	-	-	19,563,000	19,199,000	11,257,000	6,769,000	-
Amended Appendix A Totals	**$ 28,431,291**	**$ 32,779,098**	**$ 31,808,302**	**$ 35,070,699**	**$ 34,544,713**	**$ 42,168,821**	**$ 47,390,606**	**$ 66,351,020**	**$ 85,249,000**	**$ 123,394,000**	**$ 140,821,000**	**$ 161,428,000**	**$ 214,935,000**	**$ 275,358,000**

(K) - Generation Facilities Application estimates have been escalated by 3% annually.

(L) - Interest during construction for the multi-year project is calculated based on the annual capital spend multiplied by our forecast weighted average cost of capital of 6.69%.

I N T E R R O G A T O R I E S

IR-3 – Attachment 1

Maritime Electric Forecast of 2024 Capital Budget Carryovers Based on Actual Expenditures for the Period of January 1, 2024 to September 30, 2024								
Project Description	**2024 Annual Capital Budget Section**	**Actual to end of Q3 (A)**	**2024 Budget (B)**	**2024 Forecast (C)**	**Forecast Carryover to 2025 (D)**	**Total Expected Expenditures (E = C + D)**	**Expected Variance from Budget (F = E - B)**	**Notes**
Distribution Transformers	5.2	$ 8,356,438	$ 14,396,000	$ 15,513,000	$ 715,000	$ 16,228,000	$ 1,832,000	A carryover is required as replacement of PCB-containing equipment in Slemon Park has been delayed at the request of the connected customer.
Line Extensions	5.4	2,387,699	4,829,000	3,361,000	1,468,000	4,829,000	-	Under reliability driven line extensions, the Tignish substation distribution feeders project has been delayed due to municipal rezoning processes and will require $1,468,000 to be carried over into 2025.
Line Rebuilds	5.5	3,459,919	7,014,000	6,774,000	240,000	7,014,000	-	The backlot feeds relocation program requires a carryover of $240,000 due to the timing of the 2024 Capital Budget approval.
Transportation Equipment	5.8	371,005	2,674,000	834,000	1,840,000	2,674,000	-	The three line trucks in year one of procurement have been ordered and the four in year two will not be received until 2025, at earliest. As such, a carryover of approximately $1,685,000 will be required for line operation vehicles. Under small vehicles and equipment, the four passenger vehicles have been received, the pole trailer is ordered but will not be delivered until 2025, and the EV chargers project has been deferred to 2025 due to EV market dynamics. The latter two items will require a carryover of $155,000.
Substation Projects	6.1	6,414,032	14,964,000	11,410,000	3,954,000	15,364,000	400,000	Several projects will require carryovers due to not starting until Capital Budget approval in May. The total carryover amount is estimated to be approximately $3,954,000, the majority of which is resulting from a carryover of $3,210,000 for the delayed Tignish substation project.
Transmission Projects	6.2	1,537,773	2,549,000	2,210,000	339,000	2,549,000	-	The Tignish substation transmission project will require a carryover of $339,000 due to the substation site rezoning delay.
Information Technology	7.2	1,888,550	3,143,000	2,437,000	414,000	2,851,000	(292,000)	A carryover of $414,000 for the GIS upgrade to Utility Network Model project is expected due to not starting until Capital Budget approval in May and a subsequent delay in vendor availability.
Subtotal					**8,970,000**			
Capital Projects Carried Over from Prior Years	Appendix I 2023 Capital Variance Report	7,584,326	9,191,000	7,252,000	2,139,000	9,391,000	200,000	Until municipal rezoning of the Tignish substation site is approved, the purchase of transmission line T-23 is on hold and the Tignish to Alberton fibre communication project cannot be completed.These two Tignish substation-related projects will require a further carryover estimated at $480,000. Also, transportation equipment carryovers from 2022 and 2023 will require more time for vehicle delivery and a further carryover totaling $1,659,000.
Subtotal					**2,139,000**			
Total					**$ 11,109,000**			

I N T E R R O G A T O R I E S

IR-6 – Attachment 1

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	$	4,391
Tax Gross Up on Equity Return	K = G from Page 3 / (1-G)		1,138
Debt Return	K = F from Page 3		(1,859)
	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	$	1,859
Return on Common Equity	G = D X P		2,532
Total Return On Rate Base	H = F + G	$	4,391
Weighted Average Cost of Capital ("WACC")			
Debt	I		60.0%
Common Equity	J		40.0%
2025 Forecast Cost of Debt	K		4.58%
2025 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		2.80%
WA Cost of Common Equity	P = J X L X M/ N		3.81%
Forecast 2025 WACC	Q = O + P		6.61%
2025 Forecast Year End Rate Base *	**R**	**$**	**537,615**

* Per Table 6-2 of the negotiated settlement of the GRA.

Note 1: 2025 Forecast Cost of Debt (K) above has been updated from 4.92% to 4.58% to align with the 2025 forecast for Cost of Debt as reflected in the approved GRA negotiated settlement.

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	1,859
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**	**$ 7,689**
% of 2025 Forecast Revenue Requirement	**F = E / G**	**3.01%**
Forecast 2025 Revenue Requirement*	**G**	**$ 255,063**

* 2025 revenue requirement per Table 6-6 of the GRA is $255,063.

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	$ 7,689,277
Forecast 2025 kWh Sales *	B	1,606,372,142
Forecast Increase Per kWh Project Rate Impact	**C = A / B**	**$ 0.00479**
Forecast Increase Annual Cost Benchmark Residential Customer (650 kWh per month) before tax	**D = 650 kWh X C X 12 months**	**$ 37.36**
% of 2025 Forecast Annual Cost for Rural Residential Customer	E = D / I	2.25%
% of 2025 Forecast Annual Cost for Urban Residential Customer	F = D / J	2.29%
Forecast Increase Annual Cost Benchmark General Service Customer (10,000 kWh per month) before tax	**G = 10,000 kWh X C X 12 months**	**$ 574.80**
% of 2025 Forecast Annual Cost for General Service Customer	H = G / K	2.21%
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.

I N T E R R O G A T O R I E S

IR-7 – Attachment 1

Table 1
2023 Capital Budget Internal Labour and Transportation Cost Variances

Description		Budget (A)	Actual (B)	Variance (C = B - A)	Variance % (D = C/A)	Notes
4.1a	Charlottetown Generating Station – Buildings and Site Services	$ 18,000	$ 17,000	$ (1,000)	-6%	Under the material budget variance threshold of greater than a $30,000 and 15%.
4.1b	Charlottetown Generating Station – Turbine Generator	29,000	54,000	25,000	86%	Under the material budget variance threshold of greater than a $30,000 and 15%.
4.2a	Borden-Carleton Generating Station – Buildings and Site Services	22,000	14,000	(8,000)	-36%	Under the material budget variance threshold of greater than a $30,000 and 15%.
4.2b	Borden-Carleton Generating Station – Turbine Generators	32,000	119,000	87,000	272%	Higher than expected labour requirement associated with CT1 and CT2 parts and improvements.
5.1	Replacements Due to Storms, Collisions, Fire and Road Alterations	967,000	1,261,000	294,000	30%	Higher than expected labour requirement due to Government-driven road alteration work and after-hours storm response activity.
5.2	Distribution Transformers	1,034,000	1,140,000	106,000	10%	Under the material budget variance threshold of greater than a $30,000 and 15%.
5.3	Services and Street Lighting	4,090,000	4,115,000	25,000	1%	Under the material budget variance threshold of greater than a $30,000 and 15%.
5.4	Line Extensions	1,257,000	1,280,000	23,000	2%	Under the material budget variance threshold of greater than a $30,000 and 15%.
5.5	Line Rebuilds	1,446,000	1,465,000	19,000	1%	Under the material budget variance threshold of greater than a $30,000 and 15%.
5.6	System Meters	350,000	312,000	(38,000)	-11%	Under the material budget variance threshold of greater than a $30,000 and 15%.
5.7	Distribution Equipment	249,000	266,000	17,000	7%	Under the material budget variance threshold of greater than a $30,000 and 15%.
5.8	Transportation Equipment	50,000	91,000	41,000	82%	The budget was incorrectly reduced with change to multi-year purchases. This has been corrected for 2024.
6.1	Substation Projects	462,000	367,000	(95,000)	-21%	Under the material budget variance threshold of greater than a $30,000 and 15%.
6.2	Transmission Projects	1,189,000	1,203,000	14,000	1%	Under the material budget variance threshold of greater than a $30,000 and 15%.
7.1	Corporate Services	45,000	44,000	(1,000)	-2%	Under the material budget variance threshold of greater than a $30,000 and 15%.
7.2	Information Technology	469,000	491,000	22,000	5%	Under the material budget variance threshold of greater than a $30,000 and 15%.
Grand Total		**$ 11,709,000**	**$ 12,239,000**	**$530,000**		