MARITIME ELECTRIC
A FORTIS COMPANY

September 21, 2012

Mr. Mark Lanigan
Director, Technical & Regulatory Services
Island Regulatory and Appeals Commission
PO Box 577
501 – 134 Kent Street
Charlottetown PE C1A 7L1

Dear Mr. Lanigan:

Responses to Interrogatories
Maritime Electric 2013 Capital Budget

Please find attached the Company's response to the Interrogatories filed by the Island Regulatory and Appeals Commission with respect to the 2013 Capital Budget.

Yours truly,

MARITIME ELECTRIC

S. D. Loggie
Vice President, Finance and Corporate Services
and Chief Financial Officer

SDL37

Enclosures (including 2 maps referenced in Response to S-1)

S-1 Please provide a description of the distribution system which includes a summary of the overall kms of single phase and three phase distribution lines throughout PEI by category? How are lines categorized – by age, condition? Does the Company maintain a map of the distribution system categorized by age or some other reliability factor? Please provide the process the Company uses to develop the list of planned line rebuilds in each year. What is the age of the lines being replaced (except new lines) this year? What is the Company objective for age of distribution lines and how does the annual planned line rebuild program meet the Company's objective?

Please provide the same information for the transmission system.

Response:

S-1 Distribution System -

Maritime Electric's distribution system consists of approximately 4,871 kilometres of single and three phase power lines with a very small percentage (less than 1%) being underground cable installations. The distribution system is comprised of a network of poles and wires that are organized by a discrete identification system that incorporates the source (substation) and a unique number. In total there are 17 distribution substations and approximately 3,060 line segments with unique identification. Referencing the Company's 2013 Capital Budget Evidence, starting on page 4-5 are the proposed rebuild projects for next year. The second column of the table contains the line identification information for each project with the first two characters representing the substation with the following characters identifying a particular line segment. The attached map shows the geographic location of the network for each substation. The Table below provides further detail for each substation.

Substation Line Lengths

Substation	Voltage (kV)	Single Phase (km)	Three Phase (km)	Total (km)
Albany	12.5	225	103	328
Alberton	12.5	250	74	324
Charlottetown Plant	4.16	0	4	4
	13.8	20	35	55
Crossroads	12.5	203	62	265
Dingwells Mills	12.5	269	54	323
Dover	12.5	167	62	229
Georgetown	12.5	139	55	194
Hunter River	12.5	213	86	299
New Annan	12.5	214	56	270
O'Leary	12.5	267	66	333
Rattenbury	12.5	138	47	185
St. Eleanor's	12.5	45	17	62
Scotchfort	12.5	289	48	337
Souris	12.5	140	62	202
Victoria Cross	12.5	169	12	180
	25.0	197	67	264
Wellington	12.5	259	79	338
West Royalty	12.5	228	45	273
	13.8	72	49	121
	25.0	159	125	284
Total		**3,663**	**1,208**	**4,871**

Electrification of the Island was fully underway in the 1950s with poles and wires continuing to be installed throughout much of PEI in the ensuing decades. From those early beginnings, untreated cedar poles were installed and that practice continued up to the late 1980s when a decision was made to use treated pine poles exclusively. Issues of economics, deteriorating quality and life expectancy concerns of the untreated cedar poles prompted the change.

Commencing in the early 1980s Maritime Electric increased its pole replacement and line rebuilding activities and with the help of pole testing and inspection programs focused on the replacement of the untreated cedar pole lines. These activities have

systematically reduced the population of untreated cedar poles such that the 2010 Field Assessment identified only 19,400 cedar poles out of a total pole count of approximately 120,000 remaining on the transmission and distribution system. Conversely, approximately 100,000 treated pine poles have been installed. Paper based records have been maintained for line rebuilds however pole for pole replacements, new services and small extensions have not been tracked historically. In 2010 the Company incorporated a system of pole tracking in conjunction with the Field Assessment Program (FAP) that records the date, GPS location and other details of all poles installed on the T&D system going forward. Attached is a map showing the location of the remaining untreated cedar poles.

The Company continues to focus on the removal of untreated cedar poles as these are the oldest poles left on the system however, there are several other drivers for pole replacements and upgrades such as to accommodate area electrical load growth, service level improvements addressing voltage sag concerns, and for reliability reasons. As well, new services and line extensions to serve new customers also result in new construction.

Going forward, the FAP information, together with other statistics are combined in a matrix spreadsheet that weights the various aspects measured and a score is determined for each line segment with the highest scoring segment flagged for detailed review by technical and field staff. Vintage or line age is not one of the determinants as accurate information is unavailable for the majority of lines. The table below summarizes the weighting used for determining rebuild priorities.

Weighting	Criteria
40.0%	Condition, age and size of conductor
30.0%	Condition and age of pole/Density of Eastern Cedar poles
15.0%	Customers affected by an outage on distribution line
10.0%	Reliability history (Hours of outage associated with the line)
2.5%	State of vegetation management
2.5%	Density of porcelain cutouts

Response:

S-1 Transmission System -

Information for the transmission system is more complete as the date of construction and detailed location is known for each line. The map showing the various distribution areas also shows the location of each of these transmission lines. The following Table outlines the pertinent detail for each transmission line.

Transmission Line Lengths

Line	From Station Name	To Station Name	Voltage (kV)	Length (km)	Year Built/ Rebuilt or Life Extension
Cable1	Murray Corner	Richmond Cove	138	21.4	1978
Cable2	Murray Corner	Richmond Cove	138	21.4	1978
Y101	Richmond Cove	Bedeque	138	9.7	1978/2003
Y103	Richmond Cove	Bedeque	138	9.7	1978/2003
Y105	Bedeque	Sherbrooke	138	15.4	1971/2004
Y107	Borden	Bedeque	138	8.2	1971
Y109	Bedeque	West Royalty	138	41.0	1979/2008
Y111	Bedeque	West Royalty	138	41.0	1987/2008
Y113	Borden	Sherbrooke	138	23.6	1991
Y115	Sherbrooke	West Cape	138	85.0	2007-2009
T1	Sherbrooke	West Royalty	69	54.0	1983/1984
T2	Charlottetown	Lorne Valley	69	36.3	1989
T3	Borden	McCain Foods	69	4.8	1973
T4	Charlottetown	Lorne Valley	69	42.9	1969
T5	Sherbrooke	Wellington	69	19.2	1999-2003
T7	Sherbrooke	Slemon Park	69	2.4	1997
T8	Lorne Valley	Souris	69	40.8	1999-2005/2010
T8	Route 4	Georgetown	69	9.7	1972/2004
T10	Lorne Valley	Dover	69	33.3	1989/1994

Transmission Line Lengths (Cont'd)

Line	From Station Name	To Station Name	Voltage (kV)	Length (km)	Year Built/ Rebuilt or Life Extension
T11	Sherbrooke	Summerside	69	3.6	1963/1997
T12	Dingwells Mills	E.K. Wind Farm	69/138	42.8	2006
T13	West Royalty	Charlottetown	69	6.1	1983
T15	West Royalty	Charlottetown	69	9.9	1986
T21	Wellington	Alberton	69	52.2	1966/2002-2007
Total				**634.4**	

The Company believes that the continued focus on replacing the oldest poles (and related equipment) in the system (untreated cedar) is prudent in terms of effectiveness when coupled with the other considerations taken into account in the prioritizing matrix. Management is currently assessing a new method of pole testing this summer and depending upon the results of this preliminary testing, may consider further pole testing to address the aging of the pole population well before replacements are required and to develop a comprehensive, multiyear approach for planning purposes.

S-2 Does Maritime Electric benefit from any Fortis company discounted purchase pricing for capital items such as transformers?

Response:

S-2 As a member of the Fortis group of companies, Maritime Electric receives both operational and economic benefits in areas related to both annual operating and capital expenditures. While each Fortis utility remains responsible for acquiring its own services, materials and equipment, as a member of a larger Fortis buying group, the utilities together are able to maximize their combined buying power to ensure the best pricing and level of service are negotiated with suppliers. For a relatively smaller utility such as Maritime Electric, this not only results in improved pricing, but can also provide the Company with access to markets which may not have been available previously at economical prices (e.g., submarine cable insurance).

The Company regularly participates in the joint tendering or buying group process within the Fortis group for certain types of capital expenditures. As an example, in 2011, Maritime Electric participated in a joint tender for transformers with Newfoundland Power, FortisAlberta, and FortisBC. The transformer tender was unique as each utility had specific designs and other requirements to meet their own operating environment. Maritime Electric requires a specific level of transformer efficiency and a stainless steel body due to our coastal environment and other Maritime Electric specifications may differ from other Fortis utilities, nevertheless significant economics are derived from the joint buying group approach. Due to the volume of transformers included in the joint tender for the Group, Maritime Electric has seen a decline since 2010 in the unit purchase cost for most types of transformers used. The most recent joint tender completed by Maritime Electric, Newfoundland Power, FortisAlberta, and FortisBC was for wood utility poles which again provided immediate economic benefits to Maritime Electric through improved pricing. In this instance, Maritime Electric and FortisAlberta awarded their business

to the lowest bidder and, as a result, both Utilities received further pricing discounts off the low bidder's initial offer. The Company estimates that not only did it receive the best pricing through the competitive bid process but that the incremental discounts attained through the combined award of the Maritime Electric and FortisAlberta business will save Maritime Electric an additional $10,000 to $15,000 per year.

For annual operating expenditures, the group buying approach has yielded benefits in areas such as insurance, cellular phone rates, computer software, licensing and certain maintenance related costs.

A further benefit of the joint tender process among Fortis companies has been the opportunity for the Company to participate in group discussions with Newfoundland Power, FortisAlberta, FortisBC and FortisOntario to discuss common issues, best practices and products and services that lend themselves to joint tendering.

The Company continues to engage in discussions with the other Fortis utilities to identify further areas where joint tendering could yield improved pricing and service levels for common goods and services. Current discussions include opportunities in areas such as conductor, heavy fleet equipment and fleet fuel supply services.

S-3 The budget proposes to begin the third cable planning process. The Commission understands the Company continues to work with both levels of government on funding options; however, is the Company planning to proceed with the project regardless of government funding? Does the Company plan on these planning expenditures being reimbursed by government, if government funding is approved? Do these cable expenditures result in increased shareholder returns if unreimbursed by government funding? Will the planning expenditure be added to rate base and return on equity for the shareholders?

Response:

S-3 Maritime Electric believes that it is necessary to install a third cable within the next several years in order for the Company to continue to be able to provide reliable service to customers at lowest cost. In order to ensure this outcome, the Company believes the project must proceed regardless of the level of government funding and Maritime Electric is prepared to provide the funding to complete the project if necessary.

Planning, engineering and environmental studies for the land and marine aspects are a critical first step for the project. The Application proposes to treat the planned expenditure of $618,000 plus an allowance for interest during construction as a deferred charge on the Company's balance sheet until such time as the cable installation financing arrangements have been finalized. The allowance for interest during construction is also referred to as an allowance for funds used during construction (AFUDC), which represents the Company's weighted cost of financing (debt and equity) a particular expenditure. Reducing the Company's current year financing costs by the AFUDC and adding it to the deferred costs will result in the Company not earning a return on this expenditure, until such time as there is a final determination as to the ownership or disposition of the costs. In addition, the

deferral of the AFUDC will result in electricity customers not bearing any costs related to the project until a determination is made as to who will be responsible for recovery of the costs.

In regard to government funding, there are two main issues. The first issue is the extent to which the Federal government will contribute to the cost of the project. To the extent that the Federal government does provide a monetary contribution to the project, the cost to PEI will be reduced.

The second issue has to do with whether the PEI government will provide funding for the project.

If the PEI Government funds the PEI portion (total cost less any Federal funding) of the project cost, Maritime Electric would request the Province to reimburse the Company for all reasonable costs incurred by the Company in its involvement with the project, including the proposed expenditure of $618,000 for planning and environmental studies. It is the Company's intent to undertake this preliminary work in close collaboration with the Province. In the event that the Province is not able to reimburse the Company for the $618,000 plus deferred financing costs, the Company would seek regulatory approval to include the total deferred charge in its rate base and to recover the amount from customers through rates over an appropriate number of years.

If the PEI Government chooses not to fund the PEI portion of the project cost, then Maritime Electric is prepared to provide the funding based on its normal proportions of equity and debt. In this scenario Maritime Electric would own the cable and the PEI portion of the project cost, including the $618,000 plus deferred financing costs, would be added to the Company's rate base at the time the cable is placed into service. If the Federal government were to provide 50% of the project

cost, and using an equity ratio of 40%, then 0.5 x 0.4 = 0.2 or 20% of the $618,000 plus deferred financing costs would be funded by shareholder equity.

S-4 The budget includes provisional amounts for replacement of asbestos insulating material at the Charlottetown plant. The budget also includes a planned expenditure for preliminary planning for the third cable noting that it is uneconomical to further extend the life of the old Charlottetown plant. Is it necessary to perform any asbestos insulation replacement given the planned decommissioning of the plant? What would be the consequence if all expenditures on the Charlottetown plant were denied?

Response:

S-4 While the Charlottetown Thermal Generating Station (CTGS) is operational it is necessary, both from a safety and legislative perspective, to manage airborne Asbestos Containing Material (ACM) from endangering the heath of workers. Any work that is required on or around ACM must be dealt with according to legislation and safe work practices. The amounts budgeted for in the 2013 Capital Budget Application are typical expenditure levels for boilers, turbine-generators and associated piping based on past experience.

The CTGS remains a critical piece of infrastructure that must be fully operational until the day that it is permanently laid up. In order to maintain this operational readiness the facility must be maintained and capital expenditures are a requirement. For example, this past summer during the submarine cable repair work in June and July 2012 when one submarine cable was out of service, the CTGS was critical in being able to maintain electrical service to all Maritime Electric customers. Without the CTGS, there would have been rotating outages for the duration of the repairs. Management believes that the expenditures proposed in the 2013 Capital Budget Submission represent an appropriate balance of prudency and maintaining system reliability.

S-5 Is there a preliminary project plan chart for the implementation of the third cable? What date does the Company have as an objective for the completion of the third cable?

Response:

S-5 A high level project plan has been maintained and is based upon preliminary estimates using supplier quotes, engineering analysis and assumptions for some of the larger aspects of the project.

The preliminary plan is as follows:

- 2013 – Carry out Environmental Impact Assessments
- 2013 – Engage a System Impact Study at New Brunswick Power
- 2013 – Determine cable routing, substation design, transmission routing and design
- 2014 – Finalize all designs. Engineer equipment specifications and tender all equipment including cable
- 2014/2015 – Receive equipment/material and commence construction/laying of cable
- 2016 – Complete construction and commission cable, transmission lines and substations by year end.

S-6 Why is one digger truck being replaced after 14 years of age and a second digger being replaced at 23 years of age? What is the age and operating condition of the other digger trucks?

Response:

S-6 The digger trucks in the Company's fleet of line trucks will on average have a useful life of 10 – 15 years as compared to bucket/aerial units which can often be refurbished to extend their useful life. The table below provides a list of the digger trucks currently in service.

Unit Number	Year	Age	Location
09-12-51	2009	3	Central
03-12-53	2000	12	Central
03-12-61	2004	8	Central
89-12-74	1990	23	Central
12-12-54	2012	1	Eastern
04-12-59	2005	7	Eastern
04-12-60	2005	7	Western
01-12-62	2000	12	Western
10-12-63	2011	1	Western
03-12-75	1999	14	Western

Due to the nature of the construction work performed by these digger units, they are subject to a regular maintenance schedule to ensure the units are properly maintained and working in a safe and efficient manner. Unit 89-12-74, which is one of the units proposed for replacement, has been retained in the fleet for a number of years as a replacement unit to be utilized when one of the other digger trucks is taken out of service for repairs or maintenance, thereby allowing the truck's crew to continue working productively in the field. This unit performed exceptionally well over its

service life but in recent years has experienced more frequent repair and maintenance issues. Replacing this unit will permit the Company to transfer another older unit (likely unit 01-12-62) to the role of a replacement unit in order to reduce the overall repair and maintenance expenditures for the digger units and ensure vehicle availability for maximum crew staffing efficiency.

Unit 03-12-75 is also proposed to be replaced. Although this unit is within the expected useful service life range an inspection of the unit earlier in the year revealed that the truck was over the legal weight limitations for PEI's roads and highways. The Company investigated further and determined it was not economical, given the age of the unit, to effect modifications to meet the weight requirements. As a result, the digger truck is not permitted to be used on the PEI highways and therefore needs to be replaced.

The remaining digger units in the Company's fleet are considered to be in good condition and with regular maintenance should continue to perform well. It is expected that the next two oldest units, 03-12-53 and 01-12-62, currently at 12 years of service life, will require replacement within the next 2 – 3 years.

S-7 Page 3 – 2

Roof Refurbishment $123,000. Last year $67,000. Has the roof been fully replaced? Should it have been done last year when the roofing inspector identified the problems in 2010?

Response:

S-7 The roof inspection was carried out in the fall of 2010, after the 2011 capital budget was submitted to IRAC; so that 2012 was the earliest those deficiencies could be addressed through the regulatory process. The Roof Refurbishment deficiencies are being carried out over a 2 year period, with the more critical items being addressed in 2012.

The roofing system at the Charlottetown Plant is not a single roof but a composite of many roofing sections of varying construction types and ages which were developed over time as the Charlottetown Plant expanded to its present form.

Two areas are being dealt with in 2012, namely:

1. Several small areas above the turbine hall in the old end of the plant where leaking is occurring, and
2. A small sub section of the roof above the Energy Control Centre.

These two areas were the more critical items discovered during the inspections.

2013 will see the completion of the roof refurbishment over the entire roof area above the turbine hall in the old end of the plant.

S-8 Page 3-3

Why are a number of these amounts always provisional yet appear year after year?

If one is improving the lighting would it all be done at once?

Does safety equipment have a shelf life?

Response:

S-8 Due to the age of the facility, issues arise on a frequent basis that requires immediate attention. The categories and amounts are based upon Management's assessment of the outstanding priorities from a long list of small projects identified by staff, as well as amounts for routine replacements.

Major lighting upgrades were completed in the 1990's for the main lighting systems at the facility, however the lighting equipment for individual work locations within the CTGS have been dealt with on an as needed individual basis (task oriented lighting).

Safety equipment can fall into many categories depending on the specific safety equipment in question. Some safety equipment does have a finite shelf life (hard hats, fall arrest harnesses, eye wash fluid) while other safety equipment must be inspected on a regular basis (lanyards, slings, life lines, fire extinguishers) and replacement is based on the inspection results. As well, safety equipment that is used on a regular basis will wear more rapidly than equipment that is seldom used. Safety equipment subjected to a harsh environment (inside boilers, sump pits) shortens the life of that equipment, thus requiring more frequent replacement.

S-9 Page 3-4

ECC and BCC Interior Renovations:

Last year $33,400 for ECC SCADA Screen display. Also over $44,000 for roof and interior. Is that impacted by the re-locating of the SCADA equipment? Why weren't all the renovations planned and completed at one time? Is the ECC and back up constructed to withstand hurricane or serve weather?

Response:

S-9 The reason these expenditures are over two years was to allow time to situate the new display in the control room as there were several alternatives, as well, a new position was recently created that is now situated in the Control Room: Day Shift Operator. Temporary arrangements have been made however Management has redesigned the control room layout with the costs included in this budget item.

The construction standards used at the ECC and BCC are based on the construction standards in place in Charlottetown at the time of construction. Those standards were not based on hurricane conditions.

The new SCADA screen display replaced the 1970s vintage analog mimic board. The new display has been mounted on an existing wall whereas the mimic board occupies a larger section of the main ECC Control Room. The removal of the mimic board and the relocation of SCADA equipment free up office space and the budget proposed would provide for renovations to better utilize the space.

S-10 Page 3-5

What happens to the tools? Almost $50,000 over the past two years?

Response:

S-10 In any given year there are specific tools budgeted, however the majority of the expenditures are made as equipment needs arise during the year. Many of the production tools are equipment specific so any change to equipment can necessitate new tooling.

The following table summarizes the level of expenditure for tools at the CTGS Electrical and Instrumentation Shop:

2008	2009	2010	2011
$29,075	$10,246	$15,812	$27,511

S-11 Page 3-5, page 3-6

Amounts for Boiler improvements and insulation replacement are double. Is this due to the fact they were in active use during the cable repair? Is this an indication that maintenance costs will continue to climb for these units?

Response:

S-11 Deficiencies are noted in every production run, including the recent run during the 2012 cable repairs, and any deficiencies noted are prioritized for repair or rectification.

Management is committed to moderate expenditure levels at the CTGS and defers projects that otherwise would proceed in an actively used (run) facility. This mode of operation balances planned expenditures against unplanned or emergency events. The recent submarine cable run was successful from a production perspective with only minor deficiencies noted.

Future expenditures for break down maintenance are difficult to predict, however Management believes that with minimal levels of equipment operation expenditures can be expected to remain stable.

S-12 Page 3-7

Asbestos replacement of $125,000. How does this relate to the $130,000 on the previous page (3-6)?

Response:

S-12 The Company tracks expenses related to boilers and turbine-generators separately and continue to budget and track spending separately as well, hence there are similar categories for both groups of equipment.

The $125,000 is for insulation replacement for turbine-generators and associated piping while the $130,000 is for boilers.

Planned and break down work often requires the removal of existing insulation to access work areas and the extent is highly dependent upon the location within the facility. Management is responsive to employee concerns regarding the management of asbestos at the facility.

S-13 Page 3-8

$63,000 for the CT3. How many operational deficiencies have already been addressed on this unit?

Response:

S-13 Operational deficiencies that have been addressed include

- Lube oil shaft coupling (the coupling for the lube oil shaft has been replaced with a more durable coupling)
- LP/HP turbine retaining nuts replacement (the retaining nuts were identified by the OEM as an item subject to failure and were thus replaced with improved retaining nuts)
- Thermocouple change outs (the thermocouples were changed out based on a recommendation by the OEM due to a potential for foreign material damage)
- New boroscope inspection for materials (improved material was added to the inspection ports on the engine to allow for internal video inspections)
- Implemented repair for loosening of fuel temperature sensor connectors (locking devices were added to the connectors to prevent them from loosening and potentially shutting down the generator during a run)
- Engineered and implemented remote black start capability from the ECC (hardware and software were added to allow the ECC remote start capability)

This budget item also provides for the implementation of service bulletin work issued by General Electric for the safe and reliable operation of the unit as improvements are identified from either other owners or through R&D.

The summer run for CT3 was the most intensive operation of the unit since its installation. Significant operating experience was gained and several new operational deficiencies identified and rectified.

S-14 Page 3-9

Replacements of the fuel pump and lube oil cooler. Is this CT1? Was this replaced on CT2 when it was overhauled?

Response:

S-14 This project is for CT1. The overhaul for CT2 was approved for 2012 but with the need for generation for the cable repairs the overhaul for CT2 has been deferred to 2013.

Although CT2 does have a fuel pump and lube oil cooler, it is not of the same design or construction as that of CT1 and is not in need of being overhauled at this time.

S-15 Page 3-10

"Management has been deferring major life extension investments for three years as it seeks to implement an economic replacement for the Plant". Specifically what has been deferred?

Response:

S-15 In 2009 the Company hired Ross Consulting to conduct a high level evaluation of the costs associated with a life extension for the Plant. The findings indicated that an investment of approximately $35,000,000 was needed to safely and reliably extend the life of the facility for another 10 to 15 years.

Some of the projects that have been deferred are:

- Plant Essential Services Control & generator
- DCS Upgrades
- Installation of Electric Water Glass Level on Boiler 5
- Upgrade of Burner Management System on Boiler 5
- Installation of Automatic Dampers of Boiler 5 Burners
- Re-Insulation of Boiler 4
- Upgrade of Burner Management System on Boiler 4
- Blown-Down Check Valve for Boiler 4
- Non Destructive Testing of High Energy Piping and Corresponding Replacements
- Eddy Current Testing and Replacement of Air Coolers
- Replacement of Condenser Tubes of Units 10, 9, 8 7 and 6
- Replacement of Generator End Cap & Retaining Rings on Unit 10
- Replacement of Generator End Cap & Retaining Rings on Units 7 & 6
- New Turbine Supervisory Controls and Protection Equipment for Units 7 & 6

S-16 Break down the $618,000.

Would it not be appropriate to get a final decision on the Confederation bridge option prior to exploring other options?

Response:

S-16 The Company does realize that a third cable being externally attached to the Confederation Bridge is a possibility but at this time no decision has been made by the bridge owners on whether this is feasible. To that end the Company and the Province of PEI are attempting to advance this alternative to determine the feasibility of this endeavor. Maritime Electric will wait until this option is deemed technically and financially feasible before abandoning the submarine cable option.

Notwithstanding the above, MECL needs to site and build transmission line infrastructure to interconnect the ends of the new cable to the existing NB Power and MECL transmission grids. Included in the proposed budget amounts are expenditures to advance the land portions of the new interconnection.

S-17 Section 4

Is there any bulk purchasing utilized by MECL on common items, either with Fortis or other utilities?

Response:

S-17 Please refer to the response provided in S-2.

S-18 Page 4-5

What is the breakdown of single phase and three phase km of line?

Response:

S-18	Three Phase Overhead Distribution Line Length	=	1,208 km
	Single Phase Overhead Distribution Length	=	3,663 km
	Total Overhead Distribution Lines Length	=	4,871 km (see S-1)

S-19 Page 4-6

DV19250 and DM 562 are repeats of last year. Why?

Response:

S-19 The Company prioritizes capital rebuild projects for the year based on a number of factors including rebuild requests from Bell Aliant and EastLink. It is not uncommon for new rebuild priorities to arise during the year and therefore a re-balancing of priorities to be undertaken.

As a result of a request from EastLink in April 2012 to install approximately 200 poles as part of rebuild projects in the Fredericton, Ft. Augustus, and Peter's Rd. areas, the Company has deferred the 1.8 km rebuild in Wood Islands (DV19250) and 2.5 km rebuild on Rt. 310 (DM562) to 2013. Please see S-20 for other projects that have been deferred to 2013 as a result of EarthLink's requests.

Staff reviewed the EastLink request and found that the areas requested were also in need of rebuilding, albeit at a lower ranking in the prioritizing system than the projects deferred. The deferral of projects to the following year's budget was to manage capital spending.

S-20 Page 4-7

WR 1622 is repeat. Why?

Response:

S-20 As a result of a request from EastLink in April 2012 to install approximately 200 poles as part of rebuild projects in Fredericton, Ft. Augustus, and Peter's Rd., the Company has had to defer the 3 km rebuild on Winsloe Rd. (WR1622) to 2013. Similarly, the 5.3 km rebuild on Cape Bear Rd. (Rt. 18), 2 km rebuild on the Taylor Rd., and 5.5 km rebuild on the Freetown Rd. has been to 2013. Please also see S-19.

S-21 Page 4-12

How many Combination meters are now in use in the system?

Response:

S-21 At present, Maritime Electric has 2,685 combination meters (2,652 active & 33 disconnected). An active meter is one which is being billed each month. A disconnected meter is not being billed each month but it is still being read until 2 years has elapsed, then the meter is recovered and put back into stock to be used at another suitable premise.

S-22 Page 4-13

Outdoor metering tanks – What is the age of these units? Are they on the customer's property? Does the utility pay full cost?

Response:

S-22 Poole's Corner Potato Warehouse – Metering Tank #84 was purchased in 1981, making it 32 years old when removed. The Metering Tank is located on PID#=429803 which is the customer's property and the utility pays full cost for the replacement.

Dover substation – Metering Tank #94 was purchased in 1991, making it 22 years old when removed and upgraded to the most accurate metering equipment available. This unit is located inside the Dover substation on MECL PID#=582833 and the utility pays full cost of the upgrade.

Master Packaging - Metering Tank #104 was purchased in 1996, making it 17 years old when removed and upgraded to the most accurate metering equipment available. The Metering Tank is located on PID#=852038 which is the customer's property and the utility pays full cost for the upgrade.

Measurement Canada requires MECL to own and be responsible for maintaining metering equipment and MECL pays full cost.

S-23 Page 4-14

Is this replacing all the mobile radio equipment? (Will there be a complete conversion of a mix.)

Response:

S-23 The mobile radio system is comprised of repeater stations that are controlled from the master radio site at the ECC. Currently, these four repeater sites are located in Alberton, Sherbrooke, Crossroads and Summerville. The existing mobile radio equipment is at least 20 years old. The mobile radio network enables communication between line trucks, technicians, meter readers, customer services and office personnel.

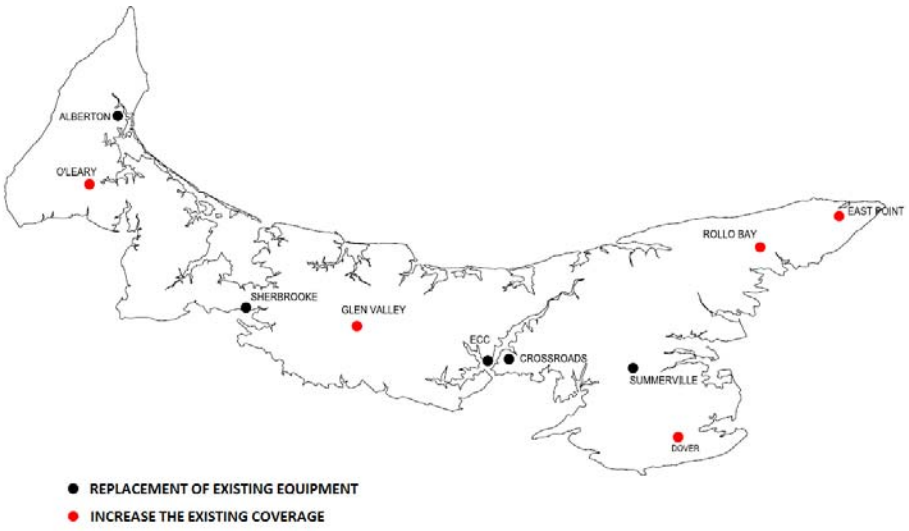
In 2013, the existing repeater sites as well as the master radio site will be upgraded with up to date antennas and radio equipment. Additional repeater sites will also be installed using new antennas and radio equipment. The 2013 mobile radio communication upgrades will improve the communication coverage across the Island. The proposed 5 repeater sites will be located at O'Leary, Dover, Glen Valley, Rollo Bay and East Point. (See diagram on following page.)

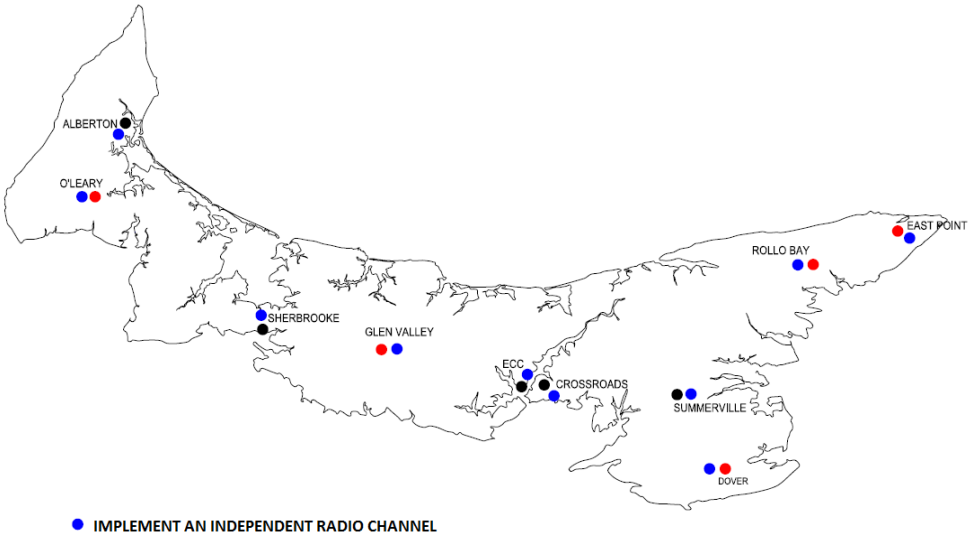
In 2014, all 9 repeater sites along with the ECC master radio site will be equipped with an additional radio and as a result two communication channels will be established replacing the single channel that is currently used. This will reduce interference and improve reliability of the mobile radio network.

The new mobile radio repeater sites will be a completed conversion and not a mix; however, the radios in the vehicles will be reused.

MARITIME ELECTRIC
A FORTIS COMPANY

MOBLIE RADIO COMMUNICATION – UPGRADE PROJECT





S-24 Page 4-16

Line tools and Equipment costs. Do these items have a life span dictated by safety?

Response:

S-24 Most line tools and equipment are inspected and tested on an annual basis while some are inspected on a daily basis by the user. Line tools and equipment are replaced as a result of deterioration or if deemed unsafe by the user or qualified inspector/tester. If the inspector/tester deems that the equipment is unsafe or fails the inspection or test the equipment is either repaired or replaced. Equipment repairs are certified, inspected and tested by qualified and competent persons.

S-25 Will the thermal imaging camera improve maintenance?

Response:

S-25 The existing thermal imaging camera is 10 years old and is in constant use. The request for a new unit will enable more inspections to be completed each year.

With this technology the Company is able to assess electrical devices to identify weak points in the system without having to turn the power off. Regular inspections with infrared cameras will provide opportunities for the Company to inspect substation equipment, transmission and distribution lines and allow the Company to be more proactive and take preventative action to avoid unplanned outages in the future.

S-26 Page 5-4

How are easement payments determined?

Response:

S-26 The Company hires property appraisers to assess the market value and injurious affection of the property for the desired easement parcel. When procuring an easement, compensation is often based upon a percentage of the value of the easement taken up to 100%. This typically depends upon the type of easement, the impact on the surface area of the property as well as the best use of the property. The estimated market value assumes that the property is for sale on the open market for six to twelve months at the time of appraisal.

S-27 Page 6-1

How many trucks operate out of the Western Service Centre? What is the benefit of the Phase one and Phase two expansions vs. other options?

Response:

S-27 The Western Service Centre is located in Sherbrooke, PEI and services the Company's customers from Rattenbury to Tignish. There are five line trucks that operate from this location. The service centre currently has a 3000 ft^2 truck bay that houses a storage area for line tools, equipment, and material and room to park four line trucks indoors. This means that there is always one line truck that is parked outside without shelter from the elements. There is also a 320 ft^2 temporary forty foot trailer that is used for material storage. In comparison, the service centre in Roseneath, PEI has a 2800 ft^2 truck bay that houses four line trucks and a 1400 ft^2 material storage area that adequately meets the needs of the Company. The advantages of additional storage space and truck bay at the Western District Service Centre are: reduction in the amount of deliveries from the main storage area in Charlottetown, increased security from theft, improved safety and increased longevity since all the line trucks will be able to be parked indoors. The phase two expansion of the facility is expected to occur immediately after phase one. In other words, the Company plans to start phase one in late fall 2013 and complete before the end of the year. Phase two will then begin in January 2014. Phase one, which is outlined in the 2013 Capital Budget Evidence is the prep work or ground work required for the expansion while phase two will include the enclosing of the expansion. The Company preferred a two phase approach as it reflects the expected construction activity.

S-28 Page 6-2

Hardware acquisitions – how much of the company IT system does this represent (i.e. all servers)?

Response:

S-28 The book value of all computer hardware at 12/31/2011 was approximately $1.245 million. While the total annual Information Technology capital budget proposed for 2013 has decreased $91,000 (or -9.5%) from 2012, the planned expenditure for Hardware Acquisitions has increased by $45,000, primarily in the category of Servers. As a result of improvements in server technology, the Company is migrating to a virtual server environment wherein multiple servers can be hosted on a small number of powerful computers. This shift in technology will yield many benefits including more efficient use of computing resources across the Company, reduced energy consumption as well as improved disaster recovery capabilities.

The additional Server expenditure in 2013 will allow the Company to increase its available server resources by 25% enabling the IT Department to continue the transition towards the virtual server environment during the years 2013 – 2015. It is anticipated that the planned level of server expenditures in 2014 and 2015 will return to more traditional levels.

S-29 $45,000 seems like a lot for a cash balancing system, what is the payback?

Response:

S-29 The cash balancing system was developed in 1996 using a technology that is no longer supported, thus making its replacement imminent. The new software will increase employee efficiency by reducing time for cashiers to transact with customers and to balance daily transactions. The second area of improvement that will be derived from the software change is in the area of Information Technology (IT) support within the Company. The current system often conflicts with newer software and operating systems. The new system will be redesigned and will become a module of the Customer Information System (CIS). This integration with CIS will result in less IT time in supporting the application and application users.

S-30 Page 6-3

What specifically is proposed under the Working alone system?

Response:

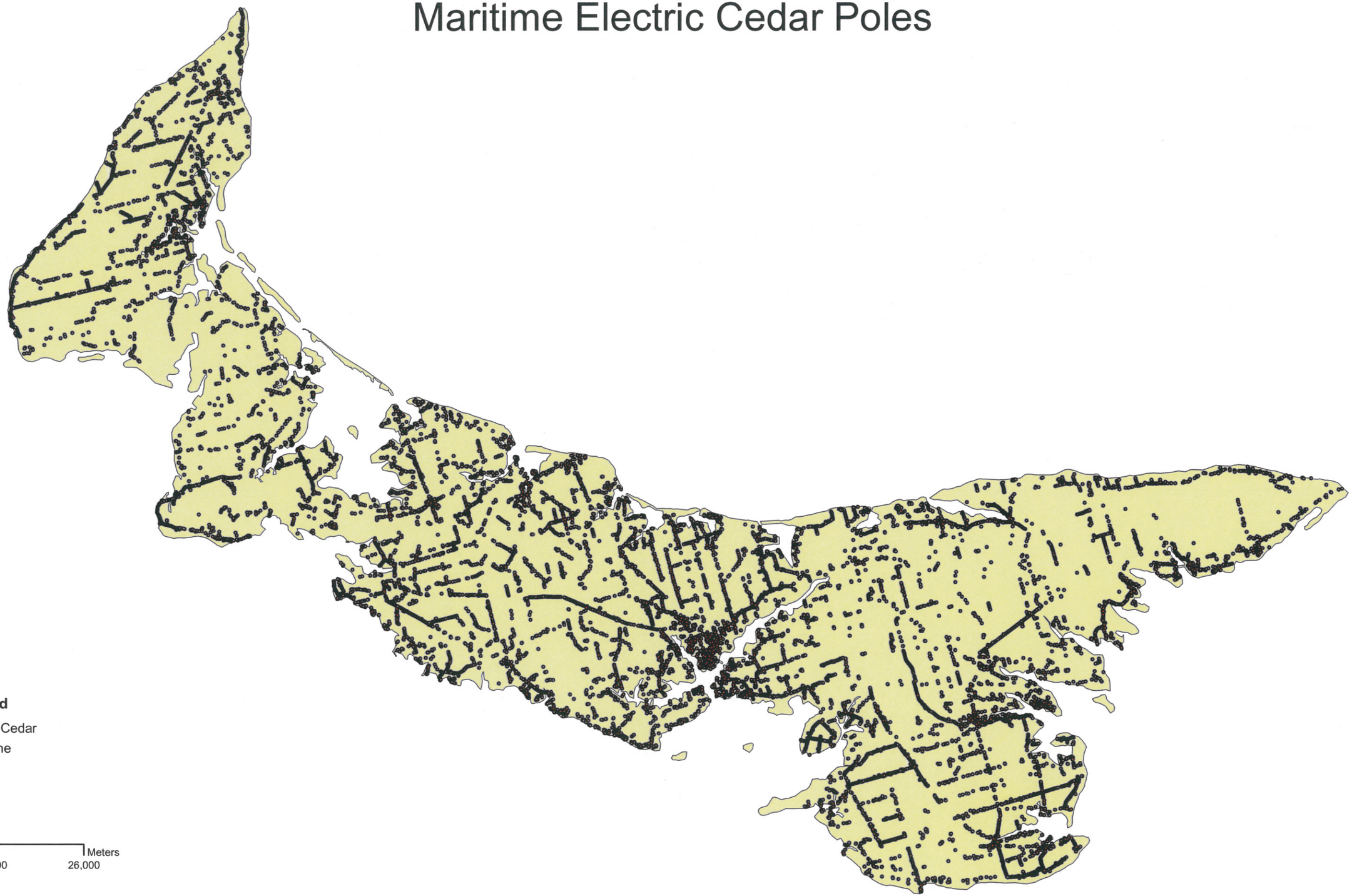
S-30 Ensuring that there are adequate procedures and controls in place to protect employees working alone is an important safety issue. There are currently several policies in place across the company designed to protect employees that are working alone. The policies' vary somewhat depending on the work environment but all operate on the premise of the employee checking in at predefined time intervals. In the event that an employee fails to check in then a series of responses and actions are performed by a monitoring employee. The working alone system will automate the process, making it a self-service function where employees can log a working alone status from the office or in the field. Employees will check in on-line where possible, record information about the work being performed, their location and set their next check in time. The employee will be required to check back using the system within a set amount of time. Failure to do so will initiate a series of events in keeping with the department's individual policy. Beyond the enhanced safety for employees, benefits include central console for viewing those working alone, historical data for reporting and improved operational efficiency.

S-31 Roof Refurbishment $123,000. Last year $67,000. Has the roof been fully replaced? Should it have been done last year when the roofing inspector identified the problems in 2010?

Response:

S-31 See response S-7.

Maritime Electric Cedar Poles



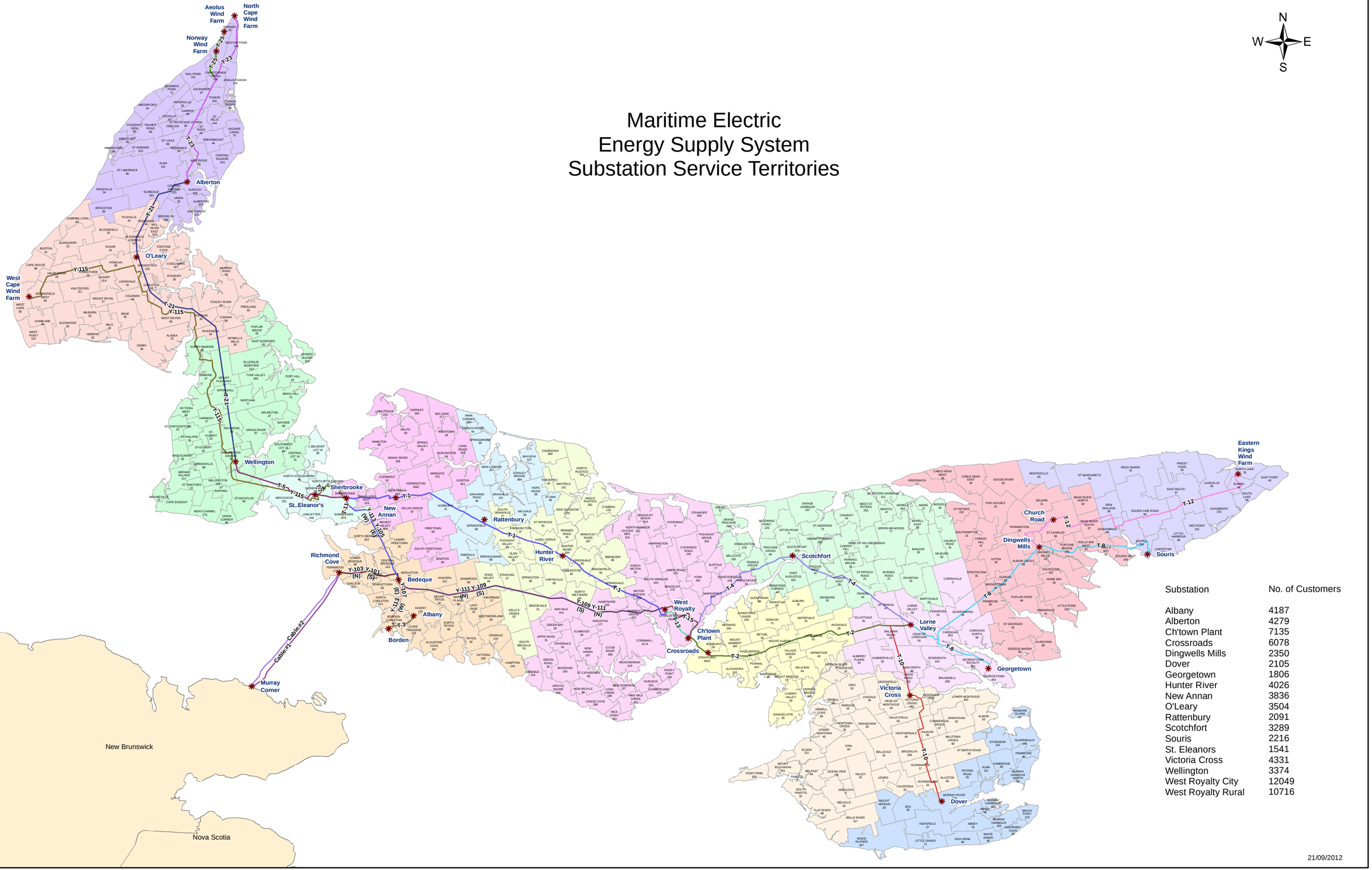
Legend

- Poles - Cedar
- Coastline

N W E S

0 6,500 13,000 26,000 Meters

Maritime Electric
Energy Supply System
Substation Service Territories



Substation	No. of Customers
Albany	4187
Alberton	4279
Ch'town Plant	7135
Crossroads	6078
Dingwells Mills	2350
Dover	2105
Georgetown	1806
Hunter River	4026
New Annan	3836
O'Leary	3504
Rattenbury	2091
Scotchfort	3289
Souris	2216
St. Eleanors	1541
Victoria Cross	4331
Wellington	3374
West Royalty City	12049
West Royalty Rural	10716

21/09/2012