MARITIME ELECTRIC
A FORTIS COMPANY

September 15, 2016

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The Island Regulatory and Appeals Commission

Mr. Mark Lanigan
Regulatory Services
Island Regulatory and Appeals Commission
PO Box 577
501–134 Kent St
Charlottetown PE C1A 7L1

Dear Mr. Lanigan:

2017 Capital Budget Filing Docket UE20725
Response to Interrogatories - Mr. Roger King

Please find attached the Company's response to the Interrogatories from Mr. Roger King with respect to the 2017 Capital Budget Application. An electronic copy will follow.

Yours truly,

MARITIME ELECTRIC

Jason Roberts
Director, Regulatory & Financial Planning

JCR34
Enclosure

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MARITIME ELECTRIC
A FORTIS COMPANY

Via email: randjking@pei.sympatico.ca

September 15, 2016

Mr. Roger King
519 Simpson Mill Rd
Hunter River PE C0A 1N0

Dear Mr. King:

2017 Capital Budget Filing Docket UE20725
Response to Interrogatories

Please find attached the Company's response to your Interrogatories with respect to the 2017 Capital Budget Application.

Yours truly,

MARITIME ELECTRIC

Jason C. Roberts
Director, Regulatory & Financial Planning

JCR35
Enclosure

1. For the Generation capital category please provide:

a. A breakdown of the $4.8M "avoided capacity and operating reserve purchases" attributable to each of the separate MECL generating sets - CTGS, Borden and CT3 – identifying each of the constituents for energy related costs (if applicable) and capacity charges separately.

b. A table listing each of the MECL generating sets - CTGS, Borden and CT3 – showing the individual:
i. Date of purchase/installation and the original purchase cost
ii. Accumulated depreciation of each set as of December 2015
iii. The book value of each set as of December 2015

1.a) Response:
The Company is unable to provide the requested information since this level of detail would disclose confidential capacity pricing information under the Energy Purchase Agreement (EPA) between the Company and NB Power. The terms, conditions and pricing under the EPA are negotiated between the parties on a confidential basis and may differ for many reasons from those negotiated with other parties. As a result they cannot be publicly disclosed.

Since filing the Capital Budget Application, the Company has reviewed and updated the calculation of the value of the avoided capacity and operating reserve purchases based upon the EPA extension, effective March 1, 2016 and the revised NB Power OATT charges, effective May 6, 2016. Using the updated pricing under the confidential EPA and the NB Power OATT, the Company estimates that the new annual value of the avoided capacity and operating reserve purchases supplied by the three facilities is now approximately $7.0 million.

1.b) Response:
The following table sets forth the year of installation of the generating units at CTGS, Borden and CT3.

Generating Unit	Year of Installation	Name Plate Capacity (Gross MW)
CTGS Turbo-generator No. 6	1951	7.5
CTGS Turbo-generator No. 7	1956	7.5
CTGS Turbo-generator No. 8	1960	10
CTGS Turbo-generator No. 9	1963	20
CTGS Turbo-generator No. 10	1968	20
Borden Combustion Turbine 1	1971	15
Borden Combustion Turbine 2	1973	25
Charlottetown Combustion Turbine CT-3	2006	50

Maritime Electric follows the Property Group method of accounting for its Property, Plant and Equipment accounts, as defined by the Federal Energy Regulatory

Commission's Uniform System of Accounts. After purchase and installation, additions and retirements from the group are recorded annually as they occur. Maritime Electric identifies the generating units by fuel type and location and maintains account records for three assets groups, steam powered (thermal) in Charlottetown, diesel powered in Borden and diesel powered in Charlottetown. The following table sets forth the accumulated historical cost net of retirements, the accumulated depreciation and remaining net book value as at December 31, 2015.

Generating Unit	Cost (Net of Retirements)	Accumulated Depreciation as of December 31, 2015	Net Book Value as of December 31, 2015
CTGS	$22,167,177	$12,253,354	$9,913,823
Borden Combustion Turbines	$12,175,649	$2,473,686	$9,701,963
Charlottetown Combustion Turbine CT-3	$34,977,548	$6,041,265	$ 28,936,283

2. For the System Meters capital category, please explain and provide data for:

a) **The annual decline, since the first installation, in the purchase cost of each of the RI and Combination system meters up to the 2015 installations.**
b) **The time-of-day customer usage information that is retrievable directly from the installed RI and Combination meters or from the MECL billing information archive.**
c) **The Itron (manufacturer) and MECL costs to retrofit (if required) the existing meters to enable the remote access by MECL of detailed customer energy use and timing information.**
d) **The choices that Itron offer for the of supply "Smart Meters" , the major features enabled by these meters and the prospective MECL purchase price**
e) **The meter/metering systems MECL used in the PEI trial project as part of the PowerShift Atlantic program recently completed?**
f) **The customer usage information that MECL collected during the PowerShift Atlantic project and how much of this information was communicated to the participating customers either by on-site meter display or compiled data that was reported back to the customer by MECL?**

2.a) Response:
When the Company started the Remote Interrogation (RI) Meter Program approximately 11 years ago, the program commenced with a focus on the conversion of the single phase meters from electro-mechanical to the digital RI meters, primarily in the Residential rate class. This focus provided the time and resources to evaluate the developing Combination (energy and demand) RI metering technology and assess the internal metering, communications and billing systems requirements to enable the eventual conversion of the Combination meters to the RI technology. The conversion of the Combination meters to the RI technology began in 2013.

Beginning in 2005, the Company's annual Capital Budget Applications approved by IRAC included a planned expenditure for the RI Meter Program. The information presented in the annual budget request includes both the planned number of meters to be installed as well as the average installed cost per meter. The annual average installed cost per meter includes both the internal costs for installation (labour and transportation) of meter related activities as well as the purchase cost of the meter from the supplier. The internal labour and transportation component of the installed cost will vary depending upon the number and types of meters installed, the geographic dispersion of the meters converted in a given year as well as the level of meter testing and replacement activities required by Measurement Canada. As the conversion program neared completion in 2013 for Residential RI and in 2015 for Combination RI, the work activities of the Metering Department shifted towards traditional growth, testing and replacement activities.

The annual purchase cost of the meters from the supplier is impacted by factors such as the term of the contract and the volumes purchased annually. When the Company implemented the

Program in 2005 it saw an initial 4.9 per cent decline in the unit cost of the meters as order amounts exceeded that purchased previously for testing. As volumes increased for the residential meter conversion the purchase price began to decrease. In 2011, the Company negotiated, based on a volume commitment, fixed pricing for 2011 – 2013 which allowed for substantial completion of the conversion of most of the Residential meters.

The following table presents a summary of the annual percentage change, since 2005, in the cost of the CP1SR Itron meter used in the typical Residential (single phase) application.

Year	Unit Price Per Meter ($)	Change in Unit Price (%)
2005	86.35	(4.9)
2006	77.49	(10.3)
2007	77.42	(0.1)
2008	66.30	(14.4)
2009	66.30	0.0
2010	66.30	0.0
2011	53.04	(20.0)
2012	53.04	0.0
2013	53.04	0.0
2014	48.00	(9.5)
2015	46.00	(4.2)

2.b) Response:
MECL uses the Itron C1SR model for its Residential (single phase only) customers and several versions of the Itron CP1XX model where Combination (three phase energy and demand) data is required. These are referred to as broadcast meters because they have no or limited memory or storage capabilities. For example, the combination meters have the ability to store and broadcast the previous month's values while the typical residential meter installed by MECL has no storage or memory abilities. As a result, the Company does not collect or retain historical interval meter reading data other than that used for monthly billing purposes.

2.c) Response:
The meters currently installed cannot be retrofitted for this purpose. Please refer to Response 2.b) above.

2.d) Response:
Itron Smart Meters have 2-way communication capability and when combined with suitable information technology infrastructure and communications systems they have the ability to provide:

- The same capabilities of the meter reading technology currently deployed by Maritime Electric, including remote interrogation, lower labour costs incurred to read meters, elimination of estimates, increased billing accuracy and tamper theft security enhancements.

- Interval or time of use data allowing utilities to introduce different prices for consumption based on the time of day and the season and to provide customers with more detailed information on consumption patterns (which should be helpful to customers in energy conservation initiatives).

- Other tools that can enhance customer service and operating efficiency such as remote connections/disconnections and outage notification/restoration.

- The most advanced features of Smart Meters include demand response features allowing the potential for customers to reduce consumption at critical times or in response to market prices, features to allow an interface with the electric utility grid load controllers to better facilitate customer demand and efficient utility supply response, and ability to communicate/interface with customer displays and programmable applications and thermostats.

The cost of a Smart Meter implementation will vary depending on the type of meter, and the information technology infrastructure and communication systems deployed. Although the unit price for Smart Meters has not changed significantly in recent years, the Company has not completed a full assessment of the cost of the meter data management and communications systems required to implement Smart Meters on PEI. In order for Maritime Electric to undertake a Smart Meter system investment it would need to satisfy itself and IRAC that the benefits to customers derived from the investment will outweigh the investment cost.

One of the most fundamental benefits that must be derived from the Smart Meter system to offset the cost of the investment is a shift in consumption by customers to off peak hours, through the establishment of a pricing structure for different times of day (lower prices in off peak hours and higher prices in peak hours). This allows the utility to defer the need to generate or purchase further energy and capacity. It is this area that poses a particular, and significant, challenge for Maritime Electric. PEI is unique in Canada in that it does not have access to low variable cost generation sources such as hydro or coal. Many jurisdictions have a fleet of generation with different sources that are used to meet customer demand. Typically during the off peak hours only the lowest cost generation is deployed. This allows a jurisdiction to set an on peak/off peak pricing model for customers that reflects the large differential in the on peak/off peak cost of generation.

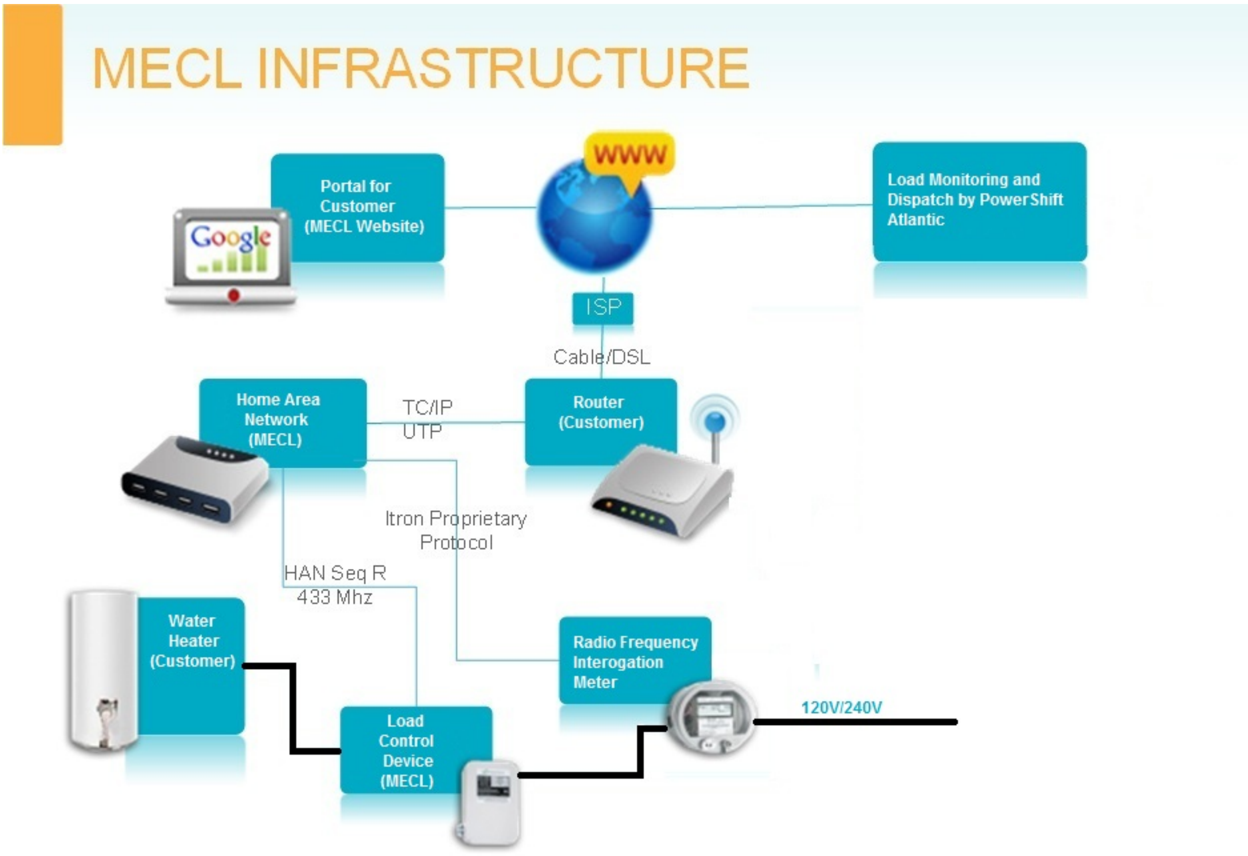
PEI has (except for base load supply from Point Lepreau and wind which is an intermittent source) a very large dependence on imported market base costed electricity. Currently there is a small price differential between on peak and off peak periods and therefore a poor foundation for an effective time of use rate structure. As a result, energy supply for PEI does not currently offer suitable price signals for consumers to act upon.

Attached is the report by the Auditor General of Ontario on her review of the Smart Metering Initiative in that Province. On page 381 there is a discussion of the requirement for a large differential between on peak and off peak prices in order to incent customers to change their usage patterns. Maritime Electric believes that the Ontario Auditor General's report supports the appropriateness of the approach that the Company has taken in regard to Smart Meters to date.

However, the Company does recognize that there may be economic value in future applications of Smart Meters related to time of wind energy generation, domestic energy storage technology and the advent of electric vehicles.

2.e) Response:

The diagram below shows the equipment involved in implementing the control of a residential electric water heater by Maritime Electric as part of the Company's participation in the PowerShift Atlantic Project.



Two pieces of equipment were installed by Maritime Electric at the customer's premises. One was a Load Control Device (LCD), installed on the water heater circuit. The LCD provided the interrupting capability that enabled the water heater to be turned on and off remotely, and the LCD also monitored the electricity being used by the water heater.

The other piece of equipment installed by Maritime Electric was the Home Area Network (HAN) module. The HAN received data from the customer's Radio Frequency Interrogation (RFI) meter and the LCD, and interfaced with the customer's Internet router. The customer's existing Internet connection was used to communicate with Maritime Electric's Head Office and the PowerShift Atlantic contractor who was developing the water heater control algorithms.

There was no change to the customer's electricity meter. The same radio frequency signals that enable the Company's RFI meters to be read by the meter reader from the street were picked up by the HAN module.

2.f) Response:

During the PowerShift Atlantic Project Maritime Electric collected water heater load data and total electricity load data by participating customers. A screen was added to the Company's website through which the participating customers could view their hourly, daily or monthly electricity usage.

3. A 2016 approved budget item was the addition of a new substation in New Glasgow at a cost of $1,374,000. Media has reported that a new routing for the transmission line to this sub-station is under consideration which presumably has delayed this project and possibly altered the cost. Could you provide the status of this project, the target completion date and explain the MECL capital budgeting process in dealing with this situation. Why is there no carry-forward commentary included in the 2017 budget application?

3. Response:

The New Glasgow Substation project has three components that were approved in MECL's 2016 Capital Budget Application: the construction of the substation, T-1 transmission line extension, and the extension of three phase distribution lines. The total estimated cost of all three components is $2,904,000. The budget breakdown of the project components is summarized below:

Project Component	Capital Budget Application Reference	2016 Capital Budget
New Glasgow Substation	6.1 a	$1,374,000
T-1 Line Extension	6.2 d	$1,030,000
Three Phase Distribution	5.4	$500,000
Total		**$2,904,000**

Over the past several months MECL has worked collaboratively with members of the community in the New Glasgow area to identify alternatives to the original proposed substation location and transmission line route. An external consultant has been hired to complete an Environmental Impact Assessment (EIA) which is expected to be filed with the Department of Communities, Land and Environment in late September. Public consultation meetings are expected to be held in October, with construction of the selected substation location and transmission line route expected to begin in November.

The estimated cost of the preferred route alternative to be included in the EIA currently does not exceed the original estimated cost of the project. Once the final transmission line route and substation location have been selected following input from the EIA process, MECL will complete a revised cost estimate and would, if necessary, seek approval for any additional amount in excess of the original budget. If the project is not completed in 2016, the carry-over work to be completed in 2017 will be identified in MECL's Capital Budget Variance Report to be filed with IRAC in February, 2017.