All our energy.
All the time.

MARITIME ELECTRIC
A FORTIS COMPANY

March 5, 2021

RECEIVED
MAR 05 2021
The Island Regulatory
and Appeals Commission

Hand Del
3:55 pm
MLA

Ms. Cheryl Mosher
Island Regulatory & Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Ms. Mosher:

UE 20731 – 2021 Capital Budget Application
Clarification Questions from Roger King

Please find attached the Company's responses to Clarification Questions from Roger King with respect to the 2021 Capital Budget Application filed with the Commission on August 6, 2020 and updated on February 1, 2021 (Commission Docket UE20731).

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

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

GCC08
Enclosure

180 Kent Street • PO Box 1328 • Charlottetown, PE C1A 7N2
telephone 1-800-670-1012 • **fax** 902-629-3665 • **maritimeelectric.com**

Via email: randjking@pei.sympatico.ca

March 5, 2021

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

UE 20731 – 2021 Capital Budget Application
Clarification Questions

Please find attached the Company's response to your Clarification Questions with respect to the 2021 Capital Budget Application filed with the Commission on August 6, 2020 and updated on February 1, 2021 (Commission Docket UE20731).

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

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

GCC07
Enclosure

Section 3.3: Estimated Impact on Revenue Requirement:
Appendix C provides the breakdown of a \$3.538M increase in Revenue Requirement driven by this 2021 Capital Budget as:

Depreciation	\$1.130M
Financing Costs	\$1.004M
MECL Profit	\$1.183M
Profit Taxes	\$0.221M

Since the capital expenditure will presumably occur throughout 2021 (and perhaps into 2022) is it correct to assume:

a. \$3.538M is the maximum annual impact on all future Revenue Requirements
b. \$3.538M is unlikely to be required for the 2021 fiscal year.

If these assumptions are incorrect, please explain.

Response:

The evidence in Section 3.3, which is supported by the calculations in Appendix C, provides an estimate of a full year impact of the proposed 2021 capital budget on rate base, revenue requirement and customer rates.

These estimates are based a number of underlying assumptions. The actual annual impact on the revenue requirement for 2021 and subsequent years will differ from the estimates provided depending on such things as the timing and amounts of the actual capital expenditures, including unanticipated cost overruns or savings, annual accounting depreciation based on Generally Accepted Accounting Principals half-year rule[1], changes to the depreciation rates currently approved by the Commission, changes in tax rates including the deduction rates for Capital Cost Allowance (“CCA”)[2], timing and amounts of the actual asset retirements and costs of removal, and other variances to the assumptions provided in Appendix C.

1 The half-year rule states that a capital expenditure is assumed to be in service for one-half of its first year, irrespective of the actual purchase or in-service date and the remaining half-year of depreciation is deducted from earnings in the final year of depreciation.

2 Under the current Accelerated Investment Incentive, an enhanced first-year allowance for certain eligible property subject to CCA after November 20, 2018 equal to either one-and-a-half or three times the normal first-year deduction for CCA. Because it does not change the total amount you can deduct over the life of the property, the incentive will lower CCA deductions in future years.

Section 5.6: System Meters: The Exclusion of a "Smart Meters" Category in the 2021 Capital budget and the 2020 revised Integrated Resource Plan (IRP):

1. The past three (3) years capital budgets have progressively increased MECL involvement in what have been termed "Smart Meter" activities:

   a. The 2018 deployment of 200 Bridge Meters ($50,000) was "to understand the communications infrastructure and data management requirements" and "to investigate the capability and functionality of these advanced meters".

   b. The 2019 deployment of an additional 375 Bridge Meters ($100,000) was "to expand this experience in providing statistically relevant load data for Residential and General Service customers".

   c. The 2020 "Smart Meters" - $300,000 capital project was set to "… allow the Company to engage third party expertise to develop a business case for the viability of full deployment and evaluate the proposals submitted through a competitive Request for Proposal process. Once these have been established, a small pilot project will be initiated with the successful vendor as a proof of concept". The planned activities were to be:

      i. Business Case Development $ 100,000
      ii. RFP Development, Evaluation and Selection 100,000
      iii. Proof of Concept/Reference Site Visit 10,000
      iv. Internal Resources 90,000

Why apparently are the past three years of sequential capital investments in "Smart Metering" not being continued for 2021?

Response:

One of the findings of the smart meter business case development work that was completed in 2020 was that Maritime Electric's current Customer Information System ("CIS") needs to be replaced for the Company to properly utilize all of the capabilities of Advanced Metering Infrastructure ("AMI") technology. The current CIS was developed as an in-house software application in the late 1980's with an expected service life of approximately 20 years. While the service life of the CIS has been extended to more than 30 years through periodic upgrades, it was determined that a vendor supplied CIS that has been specifically developed for AMI is the best option to achieve an integrated CIS and AMI solution that can leverage the full range of AMI technology benefits.

While there is no Smart Meters subcategory in the 2021 Capital Budget Application, work towards the transition to AMI is continuing under the 7.2 Information Technology budget category as project 7.2c Customer Information System/Billing. This project, which has a proposed budget allocation of $330,000, will help Maritime Electric define its CIS requirements, identify potential CIS solutions, and develop a strategy and approach for migrating to a new CIS.

Section 5.6: System Meters: The Exclusion of a "Smart Meters" Category in the 2021 Capital budget and the 2020 Integrated Resource Plan (IRP)…….\cont.:

2. Specifically, please provide updates and describe the status of the above capital projects:

   a. The 2020 business case for smart metering and the proof of concept pilot project.
   b. The deployment of 385 Bridge Watt-hour Meters.
   c. The deployment of 215 Bridge Combination Meters.
   d. The Farm Meter pilot project employing the special "Load Research Meter" for 87/88 farms.
   e. For item d), the 2017 CAS document segments the total farm category of customers and shows that in addition to the piloted 87/88 high-energy-use farms there are another twenty plus (20+) farm customers using higher energy. Please describe the current metering deployed at these remaining 20+ sites and any additional capital metering that will be required to determine the energy use and load profiles data to complement the data already included in the June 2020 "Rate Design Study".

Response:

a. The 2020 business case development project involved examining key considerations and justifications to proceed with AMI, including the financial and non-financial benefits of implementing the technology. More specifically, the work involved compiling AMI background information, defining the design scope of an AMI conversion project, identifying risks and mitigation solutions and developing an AMI conversion deployment strategy. In addition, an AMI cost-benefit financial analysis is nearing completion. This information is currently being used by the Company to prepare a regulatory application for investing in an AMI conversion project. The proof of concept pilot project/site visit, which involved a travel component, has been deferred indefinitely due to COVID-19.

b. and c. There are currently 610 Bridge meters deployed across the system. These meters capture one-hour interval data, which is collected by meter readers monthly. Initially in 2018, 200 of these meters were installed to better understand the capabilities and limitations of the technology. In 2019, an additional 410 Bridge meters were installed (610 in total) to collect data for a cost allocation study, which will be completed in 2021.

d. Installation of the 88 load research meters for the Farms Study was completed in June 2018. The resulting Farms Study report is expected to be finalized by March 31, 2021. This report will be based on 24 months of hourly data (July 2018 to June 2020), and will include the results of a December 2020 farming community survey done in cooperation with the PEI Federation of Agriculture and the Dairy Farmers.

e. No additional load research meters are planned for large farms. The existing metering at the "another twenty plus (20+) farm customers using higher energy" is a mix of kWh (energy only) meters and meters with monthly demand reading capability, depending on when the meter was installed.

3. Finally, in order to document some of the future metering projects that will likely be included in future capital funding requests, please provide commentary on:

    a. What are the future plans for replacing the aging RI meters and installing the next generation of metering system?
    b. When can interested customers expect to be able to access detailed energy and load data?
    c. When will metering be deployed to enable customers the choice of new TOU tariffs?
    d. What are the current plans for upgrading the billing and customer databases so that a new metering system can be deployed?

Response:

The Company plans to submit a regulatory application to invest in a new Customer Information System ("CIS") upon completion of the Customer Information System/Billing project (see response to question "d" below), followed by a separate regulatory application for the procurement of an AMI solution. The completion of the CIS and AMI projects is expected to require four years from regulatory approval.

a. Radio interrogation ("RI") meters will continue to be installed until the conversion to AMI technology is operational.

b. Customer access to detailed energy and load data will be available when the conversion to AMI technology is operational.

c. Metering that will enable time-of-use ("TOU") billing will be part of the AMI solution proposed by the Company. However, the establishment of TOU rates is dependent on regulatory approval of the CIS and AMI investments, and a TOU rates application.

d. The 2021 Capital Budget Application contains a project (7.2c Customer Information System/Billing) that will define the Company's requirements for a new vendor supplied CIS, identify potential supply sources and provide a strategy for migrating from the current to the new system. Upon completion of this project, the Company will prepare an application seeking approval to invest in a new CIS that is designed to leverage the full range of AMI technology benefits.

Section 6.2.c: Y119 Transmission Line:

1. To avoid any confusion with the Clyde River Substation project that was approved in the 2020 capital budget, shouldn't the text for section 6.2.c as "Y119 – Tap to Clyde River Substation" be corrected to the "Y-119 Transmission Line" heading used in the details section - Appendix Q?

Response:

Yes, the heading for section 6.2c should have been "Y-119 Transmission Line", which is the heading used in Appendix Q.

2. Appendix Q refers to three quoted options from a transmission contractor in 2018 for the replacement of Y109. While the estimates are included in the Confidential Appendix S-13, the justification text for this project references Options 3, 2 and 2A without describing the work content of each proposed option. Please provide a summary comparison of each proposed option referenced to the work content, identifying which sections of Y109 were included.

Response:

Options 2, 2A and 3 provided by the transmission contractor include estimated labour-only costs for the entire 31.4 kilometre ("km") length of 138 kV transmission line Y-109 (from Bedeque to the first steel tower located east of the Bannockburn Road). The estimate provided for each of these options was identified as an "order of magnitude estimate," as no detailed design work had been completed.

The contractor estimates were obtained to assist in determining the least cost approach for staging the rebuild of Y-109 and the construction of a new (third) west-to-east transmission line, Y-119. The contractor estimates were also used to calculate a labour cost per km and a total labour cost for the section of Y-109 (from Mount Tryon to Bannockburn Road) that will be replaced by Y-119. The total labour cost was then added to the material and other cost components, and it was determined that the least cost approach was to build Y-119 now and rebuild Y-109 later. The cost estimates provided in response to question 3 below allow for comparison of equivalent line sections with all cost components included.

With respect to the contractor pricing referenced in Appendix Q of the 2021 Capital Budget Application, the work content of options 2, 2A and 3 was as follows:

Option 2 involved replacing the tangent structures and conductor using live work methods. Corner structures would be replaced using outages with an approximate one-month total duration.

Option 2A involved replacing the tangent structures using live work methods and reusing the existing conductor. Corner structures would be replaced with outages totalling approximately ten days required.

Option 3 involved replacing the tangent and corner structures, and reusing the existing conductor. This option was based on taking the line out of service for a three-month period.

Options 2A and 3 are not viable because the conductor is deteriorating and has experienced multiple breaks; therefore, it should not be reused. Reuse of deteriorated conductor would negatively impact customer reliability, cause safety concerns and require more costly repairs/replacement in the future.

3. As the cost of this project has to be justified within the long-term plans to replace two critical transmission lines – Y109 and Y111 – please provide the current ball-park cost estimates for:

   a. Replacement of a de-energized central section of Y109
   b. Replacement of a de-energized central section of Y111
   c. Installing the new “front section” for Y111 – Bedeque to Mount Tryon
   d. Installing the new “Back section” for Y111 – Bannockburn Road to Scotchfort/East Royalty.

   As these are future cost scoping questions, possibly without the benefit of contractors’ estimates, it might be more appropriate to provide a cost range for each answer perhaps as “best case” to “worst case” or similar.

Response:

Maritime Electric’s 2020 Integrated System Plan (“ISP”) indicates that a third west-to-east transmission line will be required when the Island load reaches 375 megawatts. This is currently forecast to occur around 2030. The ISP also recognizes that the two existing west-to-east transmission lines will need to be rebuilt within this same timeframe. For this reason, a staged approach involving the early establishment of what will eventually serve as the third transmission line (Y-119) is being proposed to minimize rebuild costs with added reliability and construction safety benefits. The contractor estimates provided in Confidential Appendix S-13 demonstrates that rebuilding line Y-109 or Y-111 de-energized versus energized, will save approximately 38 per cent on labour costs (option 2A compared to option 3).

It should also be noted that the Company is not anticipating the submission of c apital projects for Y-109 or Y-111 in the near term as outlined in the 2020 Integrated System Plan. As such, the “ball-park” estimates provided below should not be considered an accurate preview of the cost that will be submitted in future capital budget applications. The “ball-park” estimates are based on historical information and conditions without consideration of specific location and construction factors. A number of factors will also cause any future applications to reflect a different cost estimate, including but not limited to the impact of inflation on material and labour costs, redesigns of the projects, new or changed standards, new or changed environmental or other legislation, and in the case of the “back section” of Y-111 as described in the question, a newly established right-of-way and associated easement costs.

a. A “ball-park” estimate to rebuild a 24 kilometre (“km”) section of Y-109 from Mount Tryon to Bannockburn Road, in its present location while de-energized, is in the order of $7 million (using a cost estimate of $290,000 per km). This estimate is based on using H-frame structures at similar spans to match the existing line and should be considered a minimum cost as construction factors (e.g., time of year, site conditions, environmental restrictions, contractor and material availability, etc.) can result in additional costs.

b. A “ball-park” estimate to rebuild a 24 km section of Y-111 from Mount Tryon to Bannockburn Road, in its present location while de-energized, is the same as provided for Y-109 in response to question 3a above, as both lines are of similar construction, share the same transmission corridor and are subject to construction factors that can increase costs.

c. A "ball-park" estimate to rebuild the 7.5 km "front section" of Y-111 from Bedeque to Mount Tryon, in its present location while de-energized, is in the order of \$2.2 million (using a cost estimate of \$290,000 per km). This estimate is based on using H-frame structures at similar spans to match the existing line and should be considered a minimum cost as construction factors (e.g., time of year, site conditions, environmental restrictions, contractor and material availability, etc.) can result in additional costs.

d. The route to connect Y-111 from the Bannockburn Road to Scotchfort as outlined in the 2020 Integrated System Plan has not yet been finalized, but the distance is approximately 60 to 70 km. Where possible, the line would be built along the roadside; however, the requirement to route the line around the Charlottetown Airport and across the Hillsborough River may result in some off-road sections. No "ball-park" estimate for "installing the new back section for Y-111 – Bannockburn Road to Scotchfort/East Royalty" has been completed and the cost would be dependent on many transmission line planning and design considerations including but not limited to the type of structures and other material specifications, line routing and easement requirements, environmental approvals and protection measures, and other construction factors (e.g., time of year, site conditions, environmental restrictions, contractor and material availability, etc.).

Updates on Peak loads data and forecasts

1. As much of the capital budget is still driven by actual and forecasted peak load growth please update the table provided in response to previous capital budget interrogatories to show the PEI monthly net peak loads for 2018, 2019, 2020 and the to-date data for January/February 2021.

Response:

Figure 1 of the 2021 Capital Budget Application, which provides a breakdown of the 2021 proposed capital expenditures by origin, shows that 21 per cent is attributed to customer/load growth, while 52 per cent is attributed to transmission and distribution plant replacement.

The table below provides the PEI monthly net peaks for January 2018 to February 2021. Values are shown in megawatts.

	2018	2019	2020	2021
Jan	280.0	269.3	286.6	265.4
Feb	258.3	272.0	275.1	271.9
Mar	221.4	246.1	248.1	
Apr	210.7	214.5	214.1	
May	185.8	203.2	208.6	
Jun	195.1	182.5	205.2	
Jul	219.9	226.9	212.7	
Aug	216.8	209.7	221.0	
Sep	189.2	190.4	200.9	
Oct	206.1	200.9	214.8	
Nov	267.1	250.1	255.3	
Dec	269.8	275.2	283.5	

2. As references in the past have referred to both MECL Peak Load and PEI Peak Load please include separately the actual MECL peak load data in the table referenced in (1) above.

Response:

The table below provides the Maritime Electric monthly net peaks for January 2018 to February 2021. Values are shown in megawatts.

	2018	**2019**	**2020**	**2021**
Jan	251.1	243.1	259.4	240.0
Feb	231.7	245.8	249.2	246.2
Mar	199.8	221.2	224.8	
Apr	188.6	192.0	193.7	
May	167.8	184.2	189.3	
Jun	177.6	165.7	187.0	
Jul	200.5	203.7	193.7	
Aug	197.4	190.5	202.0	
Sep	171.6	172.4	183.4	
Oct	187.2	183.3	195.2	
Nov	241.5	226.6	231.8	
Dec	243.2	249.5	256.8	

3. In view of the Commission's recent questions around the robustness of the NB-NS/PEI transmission interface that provides for both the import and export of energy from New Brunswick (NB) to PEI, please provide the peak load and annual energy for all PEI import and export transactions irrespective of energy sources. A useful reference point here is the completion of the undersea cables 3 &4, so this data is requested for the years 2016 to 2020 inclusive.

Response:

Import Peak Load and Annual Energy

The table below shows the import peak load and annual energy for all PEI import transactions, for 2016 to 2020.

	2016	2017	2018	2019	2020
Peak (MW)	200.9	238.2	242.8	260.2	259.4
Energy (GWh)	1,090,745	1,114,959	1,157,496	1,200,490	1,195,475

Export Peak Load and Annual Energy

Three entities export power from PEI to the mainland, and one party dominates the quantities. As such, the export energy transaction data is considered confidential and can be provided only to the Commission in confidence.

4. For the NB-NS/PEI transmission interface please identify the instances for the years 2016 to 2020 that the import of energy to PEI from New Brunswick has been constrained by a simultaneous demand for energy import to Nova Scotia from New Brunswick.

Response:

The New Brunswick-Nova Scotia/Prince Edward Island ("NB-NS/PEI") interface has a 300 MW firm transfer limitation. PEI is presently allocated all of this firm transfer, and NS is limited to non-firm transfer across the interface. The interface often has more than 300 MW capability, in which case the combined firm and non-firm schedules across the interface can be in excess of 300 MW. There are times when the interface transfer limit is less than 300 MW due to mainland system generation or transmission constraints. PEI retains all available firm transfer capability in these situations.

Maritime Electric and the City of Summerside Electric Utility make hourly reservations on the NB-NS/PEI interface for their forecast energy requirements. Other parties (such as NS Power) can acquire amounts that are surplus to PEI's needs on a non-firm basis. Scheduled amounts can be altered up to 30 minutes before the hour, at which time they are fixed. The schedule cannot be changed in the event that on-Island load is higher than projected or on-Island energy sources are lower than forecast. In this case, the utilities on PEI may have to self-supply the shortfall if there is a constraint on the interface.

The times and amounts of interface constraints include confidential commercial information for parties in NB, NS and PEI, and as such can be provided only to the Commission in a confidential nature.

Capital Budget Submission Process:
The 2021 Capital Budget application was first submitted to the Commission on August 6, 2020. Subsequently the Commission requested on September 8, 2020 more supporting documentation and compliance with the 2017 Capital Expenditure Justification Criteria (CEJC). Although this second 2021 Capital Budget application was not submitted until February 1, 2021 it now includes the MECL intention to proceed with two categories of capital expenditure without the Commission's approval.

Please explain why four (4) months elapsed before resubmitting the updated application to the Commission (on February 1 2021) which now ensures that budget approval will be late. Further what is the rationale that justifies exposing customers to the financial risk of spending a $7.5M cumulative cost of unapproved projects?

Response:

The additional documentation required by the Commission was significant. As this was the first time preparing this level of information, additional time was necessary to compile, organize, and integrate this information into the Application. This was done over a period of time during which Company resources were also responding to other regulatory matters that required significant attention by both the Commission and the Company.

As indicated in the cover letter provided with the Application, the Company recognizes that proceeding with certain unavoidable and time-sensitive 2021 capital expenditures without the Commission's approval is not ideal; however, it is necessary to ensure the provision of safe and reliable service to our customers as required under the Electric Power Act.