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Interrogatories of Commission Staff

TO: Maritime Electric Company, Limited

FROM: Cheryl Mosher, Senior Financial Advisor

DATE: January 17, 2019

RE: General Rate Application

DOCKET: UE20944

The Island Regulatory and Appeals Commission (the "Commission"), in assessing the General Rate Application submitted by Maritime Electric Company, Limited ("Maritime Electric" or "MECL"), requests responses to the following interrogatories:

<u>Section 3 – Introduction</u>

1. Please explain how the forecasted energy sales (2018-2021) contained in Schedule 3-1 (page 7) are calculated. Please provide all supporting calculations and documentation in support of the forecasted energy sales for the years 2018-2021 (inclusive).

<u>Section 4 – Provincial Costs Recoverable</u>

2. Please explain how the annual costs recoverable from customers on behalf of the Province (Schedule 4-2 at page 16) are calculated.

    a. Please provide all supporting calculations and documentation in support of MECL's calculated annual payment.

    b. Please advise when this debt is projected to be eliminated, and provide all supporting projections and calculations upon which MECL relies.

    c. Per the Collection of Debt Agreement with the Government of Prince Edward Island, Maritime Electric Company, Limited and the Prince Edward Island Energy Corporation, the costs are to be collected on behalf of the Province by MECL at a pre-set rate of $0.00536. Please explain how changing the method of payment and collection through the ECAM account is in line with the Agreement.

Section 5 – Regulatory Deferrals

3. Please explain how the ECAM base rates contained in Schedule 5-1 (page 20) are calculated. Please provide all supporting calculations and documentation in support of the ECAM base rates.

4. Please provide the monthly and year-end balances for both the Weather Normalization Reserve account and the Rate of Return Adjustment ("RORA") Account from January 1, 2016 to present.

5. What (if any) impact has the Weather Normalization Reserve had on the balance of the RORA Account since implemented on January 1, 2016?

6. If the Weather Normalization Reserve is not approved by the Commission for the period March 1, 2019 to February 28, 2022:

   a. What (if any) impact will this have on the rates, tolls and charges for electric service during this time period?

   b. What (if any) impact will this have on the balance of the RORA Account during this time period?

7. Please explain how the Post-2015 RORA Payable to Customers contained in Schedule 5-5 (page 28) is calculated. Please provide all supporting calculations and documentation in support of the forecasted RORA payable to customers.

8. Please explain how the repayment of the Post-2015 RORA Payable to Customers of $0.00250/kWh is calculated. Please provide all supporting calculations and documentation.

Section 6 – Charlottetown Thermal Generating Station Decommissioning Study

9. Various MECL documents indicate that the CTGS plant site will remain with MECL "*for the foreseeable future*". In MECL's response to IR-3 from Synapse Energy Economics, Inc. (filed November 16, 2018), it states that "*MECL intends to retain the property for future uses relating to its existing function as an electricity transmission/distribution hub*":

   a. Specifically, what future use(s) is projected for this site?

   b. Is this the best site for future generation assets?

   c. What long-term planning has been done?

10. According to MECL's response to IR-3 from Synapse Energy Economics, Inc. (filed November 16, 2018), CT3 is expected to remain on-site for an additional 35 plus years. Has MECL done any long-term analysis on whether there is a better site for diesel storage and CT3?

11. Will the full remaining CTGS site still used and useful after demolition is completed? Will it form part of the rate base?

Section 7 – Energy Sales Forecast

12. On page 40, MECL provides the forecasted energy sales for 2018-2021 and states that the forecast involves a "detailed sales regression analysis". Please provide the detailed sales regression analysis as well as an explanation of the assumptions made in formulating the analysis.

13. On Page 40, Schedule 7-1, MECL provides the actual and forecasted Energy Sales for 2016-2021. Please provide the previous forecasted energy sales for 2016 and 2017. In addition, please provide the 2018 actual energy sales.

14. On page 40, MECL states that it performed a two-year average growth rate calculation and a year-to-date growth rate calculation. From these, MECL estimates projected sales over the three year period from 2019-2021 and these estimates are set out in Schedule 7-3. Is this correct?

15. MECL has forecasted an overall energy sales growth rate of 2.6% in 2019, 2.7% in 2020, but only 1.6% in 2021 (see Schedule 7-3 at page 41). Is the growth rate for 2021 based solely on the factors set out in Schedule 7-2 (page 40)? If not, what other factors are involved in determining the growth rate?

16. Please provide the analysis and supporting documentation which forms the basis of the projections contained in Schedule 7.2 – Estimated Change in Energy Sales (page 40).

Section 8 – Energy Supply Expenses

17. With 3% or less of the projected energy supply costs during the period 2019-2021 (Schedule 8-1 at page 43) dependent upon fossil fuel costs, what is the rationale for retaining the ECAM which was instituted in the 1970s at a time when fossil fuel prices were quite volatile and fossil fuels were a major portion of energy expense costs?

18. According to Schedule 8-2 (page 44), MECL will be capacity deficient by one MW in 2020 and 2021. MECL's capacity deficiency will increase further in 2022, upon the shutdown of the final 38 MW of CTGS capacity. Is this correct? If not, please explain why not.

    a. What is the long-term plan to replace this capacity deficiency?

    b. Is it correct to conclude that if CTGS is not operational as of 2022, and there is no additional capacity acquired on PEI beyond the projected additional wind turbines, that PEI will be required to obtain 60% [(105+29+38) or 172 of its 286 MW] of its capacity needs from New Brunswick?

19. Also with respect to Schedule 8-2 (page 44):

    a. What is MECL's current capacity for on-island generation?

    b. What will MECL's capacity for on-island generation be after the planned decommissioning of the CTGS?

c. In the event MECL's on-island generation capacity is less than peak load, how does MECL intend to furnish reasonably safe and adequate service in the event energy that is purchased from New Brunswick cannot be transmitted to PEI (due, for example, to issues with the cables, the NB transmission system, etc.)?

20. What is the lead time for the construction of new generation capacity on PEI?

21. What is the maximum amount of grid capacity that is recommended to be provided from any one generating source?

22. Even if the New Brunswick supplied generation is not all from one source, is it good utility practice to have the delivery of this energy over one transmission line (namely, the NB line to Murray Corner)?

23. What assurances (if any) does MECL have that the new 30 MW wind farm will be operational by September 2020? If the new wind farm is not operational by September 2020, how does MECL intend to provide both energy and capacity?

24. The application states that although MECL intends to place the Charlottetown Plant into long-term layup starting in March 2019, it is subject to a 90 day return to service requirement under the Energy Purchase Agreement (see page 48). Please explain what is meant by this, with specific reference to all relevant provisions of the Energy Purchase Agreement.

25. On page 49, it is stated that CT3 is, in addition to its peaking purposes, to be used during periods of curtailment of contract energy and transmission curtailment by New Brunswick. Please provide the full contractual provisions which would lead to a curtailment of either contract energy or transmission.

26. Please provide justification for the internal labour costs for the Energy Control Centre Operations (see pages 50-51), together with supporting documentation. Please explain why the labour costs are forecasted to increase in each of 2018, 2019, 2020 and 2021. Please provide all calculations and supporting documentation in support of the forecasted labour costs.

27. With respect to Amortization of Deferred Charges (page 53):

a. Please provide justification for recovering costs on behalf of the Province through the Energy Cost Adjustment Mechanism ("ECAM").

b. At page 15 of the application, MECL states that PEIEC intends to restructure the financing with fixed repayment terms. If the costs are fixed and not variable, why should they be recovered through ECAM?

c. How are costs recoverable on behalf of the Province currently collected and remitted? If the costs are not currently recovered through the ECAM, please explain why Maritime Electric is proposing a change in the collection method.

d. If the Commission does not approve the collection of Provincial costs recoverable through the ECAM, what (if any) impact will this have on the proposed rates?

e. If the Commission does not approve the collection of costs recoverable through the ECAM, is there any justification for the increased ECAM base rates set out in Schedule 5-1 (page 20)?

f. At page 15, MECL states that recovering the Provincial costs as energy related costs "*will eliminate the variability in the monthly repayment amount associated with a rate rider based on monthly consumption levels*". Please explain and provide justification for this statement.

g. What (if any) impact will there be on the proposed rates if the Provincial costs are recovered by a rate rider?

28. Also with respect to Amortization of Deferred Charges (page 53), please explain and provide justification for recovering DSM expenditures through the ECAM.

Section 10 – General and Administrative Expenses

29. Please provide a detailed breakdown of the external and internal costs for the Corporate Services and Support expenses contained in Schedule 10-1 – General and Administrative Expenses (page 65).

a. Which of these costs are incurred by, or reimbursed to, Fortis or any other Fortis related company?
b. Please provide details on the Employee Future Benefit Costs in Schedule 10-2. Including details on the previous treatment of the identified gain and forecasts for this account.

30. What is MECL's policy on the payment of director's fees? Please provide a copy of the policy.

31. Please provide a detailed breakdown of compensation paid, or forecasted to be paid, to MECL's senior management and executive position employees for the years 2016 to 2022 (inclusive). The breakdown should clearly show the compensation paid to each senior management and executive position, identifying the title of the position and a breakdown of the compensation paid by salary, bonus(es), stock option(s), and any other compensation paid or payable.

Section 11 – Amortization Expenses

32. Is it correct to conclude that the CTGS contributes to neither the capacity nor energy needs for MECL after 2021 when Units 9 and 10 of the CTGS are shut down (pages 48 and 85)?

33. If CTGS will not be operational after 2021, why continue to amortize the proposed regulatory deferral account during 2022-2023, or for any period beyond 2021, other than to counter potential rate shock?

34. Is it correct that if the reserve variance account were amortized over three years (2019-2021) that the amortization expense related to CTGS, together with the deferral, would amount to $5.415 million per year? (see page79)

    a. Does this calculation assume that IRAC will approve the revised amortization as of January 1, 2019?

35. What effect on customer rates would occur if the revenue variance account is amortized only until CTGS is decommissioned (that is 2019-2021)?

36. Please provide all working papers and calculations to support the depreciation and reserve variance amortization forecasts in electronic form. In addition, include support for Appendix 9, 10 and 11.

37. MECL proposes to only amortize the accumulated reserve variance account by the variance for CTGS over a five year period. However, there is no attention given to the approximate $23 million variance identified at the Distribution Plant. Please explain why this variance has not been proposed to be dealt with in the current application.

    a. What (if any) impact will there be on the proposed rates if the Distribution Plant reserve variance is amortized over the remaining useful life of the assets?

Section 12 – Financial Objectives

38. Please explain what is meant by a “non-regulated equity contribution” (pages 90-91).

    a. Please provide the amount of the non-regulated equity contributions for 2016 and 2017, as well as the forecasted non-regulated equity contributions for 2018-2021 (inclusive).

    b. Please provide justification for non-regulated equity contributions, having particular regard to the common equity requirements in section 12.1 of the *Electric Power Act*.

    c. Please explain why the non-regulated dividends for 2018 are significantly higher than those in 2016 and 2017, and than those forecasted for 2019-2021.

    d. Please provide a description of the process MECL uses to forecast regulated and non-regulated dividend payouts.

39. In Section 12, MECL states that it is seeking a return on average common equity of 9.35% based on 40% average common equity:

    a. In the General Rate Application filed by MECL on October 28, 2015 in Commission Docket UE20942 (the “2016 GRA”), MECL was seeking a return on average common equity of 9.7% and a return on average rate base of 7.64%. What return on average rate base is MECL seeking in the present application? If MECL is not seeking a return on average rate base, please explain why.

b. In the 2016 GRA, MECL derived its revenue requirement based, *inter alia*, on the return on average rate base (see 2016 GRA at page 141). In the present application, MECL derived its revenue requirement based, *inter alia*, on the return on average common equity (see page 152). Please explain and provide justification for this change in the derivation of the revenue requirement.

c. What would MECL's estimated revenue requirement be in the present application if it was derived from the return on average rate base, rather than the return on average common equity?

40. What return on average rate base has MECL earned in each year from March 1, 2016 to present?

41. If the return on average rate base was greater than that approved by Commission Order UE16-04 (7.43% in 2016, 7.17% in 2017, and 7.05% in 2018), are the over-earnings recorded in the RORA Account to be refunded to ratepayers?

a. If no, please explain why.

b. If yes, how much was contributed to RORA in each of 2016, 2017 and 2018 due to overearnings on the return on average rate base?

42. Please provide a Schedule of Inputs for 2019-2021 comparable to Appendix 2 (Schedule of Inputs) attached to Commission Order UE16-04.

43. Appendix 2 (Schedule of Inputs) attached to Commission Order UE16-04 is based on forecasted numbers for 2016-2018:

a. Please provide an updated Appendix 2 which shows the forecasted versus actual values for 2016, 2017 and 2018 for each line item contained in Appendix 2.

b. Has there been any material change in any of the inputs? If so, please disclose and explain.

44. Appendix 2 (Schedule of Inputs) attached to Commission Order UE16-04 includes forecasted transmission revenue for each of 2016, 2017 and 2018. A revised OATT was approved by the Commission effective August 1, 2018 (see Commission Order UE18-05). What (if any) impact has the approved OATT had on the 2018 transmission revenue as forecasted in Appendix 2?

45. Please advise which Canadian regulators have allowed an earnings sharing mechanism and which have disallowed it. For those regulators that have allowed an earnings sharing mechanism, please provide full details of the approved earnings sharing mechanism.

<u>Section 13 – Cost Allocation Study</u>

46. MECL is seeking to further delay changes to the residential second block. If the Commission does not allow the proposed phasing out of second block, and instead orders that second block be eliminated immediately:

a. What (if any) impact will this have on the proposed rates for each class of residential customers?

b. What (if any) impact will this have on the revenue to cost ratios for each class of customers?

47. If the Commission determines the second block will be increased to 5000 kWh immediately, what (if any) impact will this have on the proposed rates for each class of residential customers?

48. What rates would be required to be charged to each of the customer classes set out in Schedule 13-7 if IRAC mandated an immediate change in rates to bring the revenue to cost ratio for each of these classes to 1:1?

49. What rates would be required to be charged to each of the customer classes set out in Schedule 13-7 if IRAC mandated an immediate change in rates to bring the revenue to cost ratio for each of these classes within a 95% -105% revenue to cost ratio?

50. What rates would be required to be charged to each of the customer classes set out in Schedule 13-7 if IRAC mandated an immediate change in rates to bring the revenue to cost ratio for each of these classes within a 90% -110% revenue to cost ratio?

51. Please provide a table showing, on a yearly basis, the percentage change in rates for each customer class if IRAC were to order that rates be adjusted to a 1:1 revenue to cost ratio with the change being phased in over a 4 or 5 year period.

52. Please provide a table showing, on a yearly basis, the percentage change in rates for each customer class if IRAC were to order that rates be adjusted to a 95% - 105% revenue to cost ratio with the change being phased in over a 4 or 5 year period.

53. The rationale for equalizing rural and urban residential service charges appears to be based upon the fact that there is no material cost difference to service these different classes with changes in meter reading technology and increases in rural customer density (see page 128). Why is it appropriate to maintain a higher monthly service charge ($26.92) for seasonal residential customers when the urban/rural residential rate has been equalized at $24.57 per month?

54. The revenue to cost ratio for the General Service rate class is currently 122. Please explain why the current application does not rectify this issue, and provide justification for the continuation of a revenue to cost ratio of 122 for General Service customers.

<u>Section 15 – Impact of Proposal on Customers</u>

55. The percentage annual increase in electric rates for residential customers is based on the continuation of the Clean Energy Price Incentive for the next three years. The Incentive is a Provincial Government rebate of 10% on the first 2,000 kWh per month of energy consumed by residential customers (page 161).

a. MECL states that the Clean Energy Price Incentive "*is expected to continue to provide relief during the proposed three year rate setting period*" (page 161). Please provide justification for this assumption. Does MECL have any written agreement or assurances from the Government of Prince Edward Island that the Clean Energy Price Incentive will continue without change until February 28, 2022?

b. What will the total annual cost, and percentage annual increase in rates, be for a residential customer in each of 2019, 2020 and 2021 if the Clean Energy Price Incentive is removed from the calculations in Schedules 15-2 and 15-3 (pages 161-162)?

Additional interrogatories may follow.

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