Maritime Electric Co.Ltd. (MECL) 2019 Capital Budget Application (UE20728) – Comments to IRAC

Introduction

Although the Commission's order # UE17-03 pertaining to MECL 2018 Capital Budget Application continued the rote practice of approving, without any amendments, the requested capital budget, the Commission did set a new standard for MECL in preparing future capital budgets. Specifically the Commission required an approved "Capital Expenditure Justification Criteria" (CEJC) document as a baseline policy for future budget applications and set five (5) detailed objective content requirements to be included in the 2019 budget application. MECL's compliance with the baseline policy manifests as the introduction of six (6) expenditure classifications with one primary classification labeled as "Justifiable" and consuming 46% of the total capital expenditure requested. However, despite presenting the highest total capital expenditure request of all previous years, most of the five (5) detailed objective requirements appear to have been omitted with MECL continuing a subjective justification for each capital project. There is no indication of any stringent financial critique or consideration of a balance between reliability of electricity supply and customer affordability, no commentary on competing capital requirements and priorities, no obvious attempts to align the capital expenditure with the low growth in delivered energy and no metric comparisons with other utilities.

Customer Cost, MECL Financial Return and Capital Affordability

All costs arising from new annual capital expenditures are passed on directly to MECL customers as an electricity rate increase. For MECL there is no operating cost impact or financial risk, simply an increased shareholder value and an improved Return on Investment (ROE). For the $33M expenditure requested customers will pay an additional $1.2M for added MECL ROE (profit), $0.9M for debt financing and approximately $0.9M for future annual depreciation charges – an additional cost of $3.0M each year collected by increasing customers rates. Is an annual capital budget at 17% of annual revenue affordable and comparable with other low growth Canadian Utilities?

Peak Load Growth and Affordable Capital Expansion:

Over the last five (5) years MECL annual capital budgets have been driven by the forecasted growth in peak load. The approach taken by MECL so far appears to be that the peak load forecasts included in the 2017 Integrated System Plan must be preempted by expanding the infrastructure at whatever cost. No attempt to improve the system Load Factor (the ratio between the average load and the peak load) from the static and low 55% is evident either currently or for the future. This means that the expanding infrastructure continues to be underutilized by 45%. Equally there is no notion of affordable capital budgets – the totaled cost of all the preferred projects is the amount submitted! How is the Commission expected to deliberate when the balance between the reliability of electricity supply and customer affordability is not articulated?

<u>Conclusions from the New Expenditure Classification Groupings:</u>

Excluding the two (2) single entry classifications of Capitalized General Expense and Interest During Construction (2.9% or $956,000), the "Mandatory, Recurring and Work Support Services" can be considered collectively as the baseline annual operating capital requirement. This is just over 50% of the requested $33,277,000 or $16,959,000. The remaining 46% or $15,362,000 constitutes the "Justifiable" classification which manifests as a set of projects for improving the safety of employees and consumers or improving the reliability of supply for consumers or simply the provision for forecasted changes in the future. This classification should be better described as "Discretionary" where the included projects are not mandatory, are on different time lines and are competing funding requests for mitigating the wide span of all operating risks. It is this set of projects that requires the application of the five (5) detailed objective evaluation criteria as detailed by the Commission in UE17-03. As risk mitigation is the core objective of these projects, an alternative priority ranking method can be simply obtained by rating the assessed "seriousness if it occurs" risk between 1 and 10 combined with the "probability of occurrence" risk between 1 and 10. With either method, the result will be a hierarchy of separate priority projects that permits the selection of expenditure based on a balance between reliability of electricity supply and customer affordability. <u>It should be noted that this process does not eliminate the lower priority projects but simply defers some projects to future years</u>.

<u>The Lorne Valley 69 kV Switching Station Expansion – project 6.1.a @ $2,820,000</u>

This project requires a stringent technical and financial review – justification alone to defer this project. At least three major issues exist.

1) The (July) 2017 Integrated System Plan cites this project cost at $1,740,000. What has driven the $1M+ additional cost?
2) Past evidence of recent installations of new substations shows that the interconnection and integration of new substations has required additional "overhead" costs ranging between 113% and 147% but not shown in the project descriptions. Taking an average of these overhead factors suggests that the total cost of the Lorne Valley project could be around $6.5M
3) The text describes that "the substation design will also incorporate a future 138kV connection into Lorne Valley which will be required when the island load grows to 350MW which is forecast to occur in 2030". How can this section of the justification be accepted when the peak load forecast means that the two new mainland undersea cables will be only fourteen (14) years old yet their capacity (360MW) will be exhausted?

<u>The Deployment of Bridge Meters - $100,000</u>

This project is the second phase of deployment of Advanced Metering Infrastructure (AMI) capable meters and signals that MECL is now moving, albeit slowly, to address the importance of peak loads and hopefully will soon start engaging customers in a use-control program based upon new peak load centric tariffs. The issue with this project request, in terms of dollar amount and descriptive text, however is fourfold:

1) Hourly load data is already collected for a significant sample of General Service customers using standard combination meters; deployment of bridge meters should focus upon the larger group of Residential customers
2) Available data shows that:
    a. using standard combination meters, peak load is currently measured and charged for 2800 General Service customers from a customer population of over 7000 responsible for 27% of coincident peak load, as compared to,
    b. peak load is not measured or charged for a Residential customer population of over 55,000 responsible for 55% of coincident peak load.
3) Interrogatories response informs that "a stratified random sampling method" has set the number of load measuring AMI meters at 573 (171 for Residential customers and 402 for General Service) in order to satisfy the next cost allocation study set for 2021. The critique here is:
    a. An important aspect of collecting Residential load data is being able to share peak load data with customers as part of a necessary engagement program. Many General Service customers are already informed by the Demand charge included in their monthly bill.
    b. With "fairness of the rates charged for each customer class" as a project objective, the 2017 cost allocation data already provides enough base data to make tariff changes, as expected in the imminent 2019 Rate Application. Waiting until 2021 for refined data to address peak load control is too late.
    c. With interrogatories response confirming that hourly data has been captured and retrieved successfully from the bridge meters deployed this year, deployment of Residential bridge meters can and must be accelerated.
4) The July 2017 Integrated System Plan does not include a section on System Meters/AMI deployment either for capital expenditure reference or linking peak load measurement with the inevitable required change in customer tariffs. With the RI meters, deployed since 2004, presenting possible increased "end-of-life" risks and the additional system support required for AMI deployment, careful and visible planning is paramount.

Commission Order Proposals:

1) Amend the Application by separating the baseline annual operating capital requirement of just under $18M from the remaining $15M "Justifiable" classification and request MECL to apply the five (5) detailed objective evaluation criteria (or equivalent) as detailed by the Commission in UE17-03 to. This "Justifiable" classification should be relabeled as "Discretionary" and the results of the objective evaluation presented as a hierarchy of separate priority projects that permits the Commission to defer expenditures based upon a balance between reliability of electricity supply and customer annual affordability.

2) As a starting point for which projects should be deferred to future years, two obvious candidates are:
   a. The Lorne Valley 69 kV Switching Station Expansion – project 6.1.a ($2,820,000) and
   b. The Combustion Turbine 3 Turbo-Generator Overhaul - project 4.3.a. ($1,235,000)

3) Other non-immediate projects for deferral consideration are:
   a. Bonshaw circuit Line Extension – project 5.4.b ($1,040,000),
   b. Accelerated Distribution Component Replacement – project 5.5.c. ($1,450,000),
   c. Station Modernization Program – project 6.1.d. ($685,000).

4) Delay the approval of the System Meters request for $655,000 until the Integrated System Plan includes a System Meters section that addresses both meter replacement and AMI deployment. While this section will iterate somewhat the Commission should direct that the first (draft) version should expedite the adoption of bridge meters and minimize the replacement of RI meters for Residential customers.