Maritime Electric Co.Ltd.(MECL) 2017 Capital Budget Application (UE20725) – Comments to IRAC

Customer Cost and MECL Financial Return - A Baseline Regulatory Challenge

All costs arising from new annual capital expenditures are passed directly on to MECL customers as an electricity rate increase. For MECL there is no operating cost impact or financial risk, simply an increased Return on Investment (ROE). For an annual $30M expenditure customers will pay each year $1.1M for added MECL ROE (profit), $0.8M for debt financing and approximately $0.8M for future annual depreciation charges – an increased annual cost of $2.7M all due from customers. In exercising the "fair and equitable" regulatory balance between customers' costs and the utility's objective of maximizing profit I urge the Commission to be unrestrained by any related estimated input factors presented in previous applications including the recent 2016 Rate agreement between MECL and the PEI Government.

2017 Capital Budget Application Critique:

MECL continue to adopt the formats and content of all previous capital applications without any indication of charting a different strategy for capital expenditure. There is no commentary in the application on competing capital requirements and priorities, no obvious attempts to align the high capital expenditure with the low growth in delivered energy, no metric comparisons with other utilities or any provision for future strategic operational shifts, including the imminent commissioning of the new mainland cables. The generation and system meters categories are particular examples of historical rather than future planning:

Generation: PEI fossil fuel generation hitherto has been primarily for security of supply for the limited capacity of the 200MW mainland cables. MECL justification for repeated annual generation capital upgrades of between $1M to $2M has been the avoided annual costs of $4.8M for both capacity and operating reserve purchases from NB Power but it should be noted that the annual cost of operating the PEI generation suite continues to be between $5M and $7M.

Now that the new mainland cables project is under construction, with commissioning due early 2017, the requirement for security of supply is eliminated and a PEI generation strategy shift is required. Future annual operating/capital costs of generation equipment can now be weighed directly against the negotiated cost of annual capacity/reserve purchases. By setting a strategy of eliminating generation capital starting with the already planned retirement of the CTGS plant, new expenditures on fossil fueled generating equipment should now be set at zero with a focus to eliminate the $5M to $7M annual generating operating costs.

System Meters: The installment of the RI technology is complete. The capital expenditure prescribed is for new customers or failed units which should now be categorized as an

operating expense. As already exampled by other electricity utilities, capital provision for starting a smart metering program and the phased deployment of smart meters for all customers should be included in future capital budgets. The opportunity of future energy use reduction, reduced energy cost opportunities for MECL customers and the evolution towards an island-wide smart grid must start.

Commentary on Interrogatories Responses from MECL

Generation:

1) The original request for clarity on the avoided annual costs of $4.8M for both capacity and operating reserve purchases from NB Power was denied on the basis of confidential information. A supplementary request for clarity on the inclusion of OATT charges in the avoided annual costs has not been answered in time for this IRAC input.
2) The book value of MECL generation assets as of 2015 was $48.5M. This "debt" costs customers approximately $3M in annual financing costs – another factor that should be used in balancing the cost of maintaining generation as compared to purchase capacity from NB Power

System Meters:

In answers to a series of questions related to providing customers with time-of-day energy use information, one response from MECL provided a detailed description of the features of smart metering but concluded that "suitable price signals for consumers to act upon" were not offered in NB Power EPA costs. However increases in coincident peak load leads to increased MECL delivery costs; EPA capacity purchases from NB Power (or maintaining PEI generation) and increased PEI transmission line capacities together have significant annual cost implications and result as an "overhead" to the cost of each unit of on-peak load. By including this overhead cost as a functionalized cost of delivery, the true operating cost differential of on-peak load would be shown. Two derived supplemental questions for MECL were presented:

1) Why is the total operating cost of on-peak energy not used in describing the PEI case for or against a different pricing structure for different times of the day?
2) Why is the opportunity not taken of introducing customers to the notion of time-of-day practices initially to control the increasing coincident peak load but also for the future support of integrating increased, PEI generated, renewable energy?

These questions have not been answered in time for this IRAC input.

In reviewing the current 2017 OATT application, a subsequent related MECL planning anomaly is revealed. The traditional Appalachian method of calculating different tariffs for on-peak transmission use has been continued in the 2017 application but without presenting supporting differences of operational costs between on-peak use and off-peak use. A sound

reason here has to be one of encouraging ideal-use behavior by customers to avoid potential peak time issues for the future. Surely this precedent should be applied to the concrete evidence that past and future costs of supplying coincident peak load to customers have and will continue to increase?

Related to the current status of the PowerShift Atlantic project sites, the final supplemental question posed to MECL attempted to provide focus to previous proposals that deployment of smart meters should begin and were there any plans for an expanded project in the future? This question too has not been answered in time for this IRAC input.

Proposed IRAC Order Content:

1) Deny the $1,253 000 proposed expenditure on existing generation equipment subject to new contract negotiations between MECL and NB Power for increased capacity and reserve allocations.
2) Deny the $542,000 proposed expenditure on system meters, transfer the cost of replacing existing meters as an annual operating expense and direct that any new capital in this category should be allocated to the purchase of smart grid compatible meters.
3) Direct that an MECL report be compiled as soon as possible on the transition plan for a PEI wide smart grid.

<u>Future Planning Commentary</u>

As a requirement for accepting any future regulatory applications, I continue to urge the Commission to seek a documented framework from MECL within which each application can be evaluated and the influence and connection between them understood. As the Commission is aware, this framework for Utilities is usually an Integrated Resource Plan (IRP) which includes forecasts, risks and costs for at least the next 10 years. Without such a future planning document that is frequently updated and frequently referenced, logical and connected decisions cannot be made. An IRP is now especially relevant with the PEI Government's recent updating of the province's energy strategy which provides objectives and legislative context for MECL plans going forward.