All our energy.
All the time.

MARITIME ELECTRIC
A FORTIS COMPANY

May 16, 2025

Ms. Cheryl Bradley
Island Regulatory and Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Ms. Bradley:

Supplemental Capital Budget Request
On-Island for Security of Supply Project – Docket UE20742
Response to Interrogatories from Synapse Energy Economics
On Behalf of Island Regulatory and Appeals Commission

Please find attached the Company's responses to interrogatories from Synapse Energy Economics on behalf of the Commission with respect to the On-Island Capacity for Security of Supply Project received on May 2, 2025.

An electronic copy of this submission will be forwarded shortly.

Yours truly,

MARITIME ELECTRIC

M Francis

Michelle Francis
Vice-President, Finance & Chief Financial Officer

MF27
Enclosure

Studies Form and Purpose of Quantitative Analyses - On-Island Capacity Studies

IR-1 References: "Capacity Resource Study, Evaluation of Various Technology Options for Maritime Electric Company", December 9, 2022; and "Extreme Weather Event Capacity Impact, Addendum to December 2022 Maritime Electric Capacity Resource Study", July 12, 2023; and "Maritime Electric Application and Evidence", December 18, 2024, including at page 7, "2024 net present value ("NPV") analysis", and including the confidential Appendix E ("Net Present Value Inputs and Calculations") of the December 18, 2024 Application and Evidence:

a. Summarize the specific methods and objectives of the December 2022 and the July 2023 quantitative analyses conducted to determine on-Island capacity supply needs, including the modeling tools utilized, the economic or other metrics used to evaluate the amount and the type of resource options, and if or how the analyses built upon Maritime Electric's 2020 Integrated System Plan (ISP).

b. Were any explicit capacity expansion and production cost analyses - using industry standard integrated resource planning tools to develop optimal or near optimal supply plans - conducted for PEI or the Maritime Electric territory on PEI, for either the analysis contained in the December 2022 report, or for the updated analysis contained in the July 2023 report?

   i. If so, state which modeling package was used and provide all modeling outcome results and input assumptions utilized (in Excel file format).
   ii. If not, explain if, or how the combined studies (December 2022 and July 2023) determined an economically optimal or near-optimal resource plan for On-Island capacity supplies.
   iii. If the studies noted did not determine an economically optimal resource plan, explain why.

Response:

a. The core objective of the December 2022 analysis was to help identify future resources and associated resource portfolios that would help address Maritime Electric Company Limited's ("Maritime Electric" or the "Company") most urgent generation needs, namely: (1) fulfilling its energy and capacity obligations; (2) improving its ability to serve load in the event of curtailment from the mainland or electrical disconnection; and (3) achieving sustainability targets. The July 2023 report focused on the extreme cold weather that occurred from February 3 to February 5, 2023, which resulted in Prince Edward Island's ("PEI") peak load reaching 395 megawatts ("MW"), 22 per cent higher than the previous record peak of 323 MW set in 2022. The magnitude of the increase in peak load necessitated an update to the amount of recommended capacity to meet Maritime Electric's needs from the December 2022 analysis. In addition, the extreme cold weather event highlighted a close call to a potentially catastrophic event where curtailment from the mainland, combined with the low amount of dispatchable capacity installed on-Island, nearly resulted in load shedding on PEI during dangerously cold weather.

The December 2022 analysis is not an Integrated Resource Plan ("IRP"); it is a Capacity Resource Study ("CRS") with a key focus on system reliability planning based on industry guidance, such as the North American Electricity Reliability Corporation's ("NERC") 2024 Reliability Assessment Process.[1] The core analysis was primarily an aggregation of past and forecasted energy and capacity obligations versus potential future additions, and was performed using Excel. Excel is appropriate given the limited fuel and generating technologies available to PEI and the small size of the PEI electrical system.

The December 2022 and July 2023 analyses broadly align with the findings and recommendations of the 2020 ISP. The analyses provide additional detail and updates, including a thorough review and comparison of potential generation and storage technologies. The July 2023 analysis also included a more detailed review of how PEI fits into the regional electrical system, including a regional review of events during the February 3 to February 5, 2023, extreme cold weather event (i.e., polar vortex) and the significant increase in peak load experienced by Maritime Electric since 2020, among other items.

b. A production cost and capacity expansion software was not required for the analysis. As noted in response to IR-1(a), the December 2022 analysis is a CRS, not an IRP, with a key focus on system reliability planning.

  i. Not applicable.

  ii. As explained in the December 2022 analysis, the three primary objectives of the analysis were helping Maritime Electric to (1) fulfill its energy and capacity obligations, (2) improve its ability to serve load in the event of curtailment from the mainland or electrical disconnection, and (3) achieve sustainability targets. The July 2023 report further emphasized the importance of objective (2) above, as the polar vortex event's impact on the regional electrical system resulted in a close call curtailment event for Maritime Electric. There are few resources well-suited to PEI that can meet these objectives; therefore, determining an economically optimal or near-optimal capacity resource plan did not require a detailed production cost model and capacity expansion software. Instead, Sargent & Lundy LLC ("S&L") compared resource capital and fixed operations and maintenance ("O&M") costs (see appendices of the December 2022 report) to determine economically optimal or near-optimal capacity resource recommendations.

  iii. Please refer to response to IR-1(b)(ii).

[1] The NERC 2024 Reliability Assessment Process if available at: https://www.nerc.com/comm/RSTC/RAS/ERO%20RA%20Process%20Document.pdf#search=ERO%20Reliability%20Assessment%20Process%20Document

IR-2 Reference: December 2024 Application and Evidence

a. Confirm, or explain otherwise, that the December 2024 "Net Present Value [NPV] Analysis" contained in confidential Appendix E represents a singular cost comparison for one specific portfolio (containing 10 MW BESS, 50 MW CT, and 90 MW RICE capacity resources) in comparison to procuring the portfolio-equivalent amounts of capacity and a portion of load following and spinning ancillary services otherwise purchased from New Brunswick Power.

b. Confirm, or explain otherwise, that the NPV analysis in confidential Appendix E does not represent a comparison of costs or benefits of potential alternative mixes of on-island capacity resources associated with the 150 MW of total capacity in the specific scenario reviewed.

c. Confirm, or explain otherwise, that the NPV analysis does not attempt to find an economically optimum resource plan for Maritime Electric's system for the 50 years considered in the Net Present Value assessment, or for any portion of the 50 years analyzed.

d. Provide in Excel format (with all formulas intact) all of the confidential Appendix E tables.

e. What is the source of the New Brunswick Power rates included in the NPV Analysis table in confidential Appendix E and what assumptions were made if any extrapolations of such costs were used?

f. Confirm, or explain otherwise, that any transmission tariff costs associated with import of capacity or energy from New Brunswick is excluded from the avoided cost estimations contained in the NPV analysis table in confidential Appendix E.

Response:

Questions (a) through (f) relate to the net present value ("NPV") analysis contained in the On-Island for Security of Supply Project ("Project") Application ("Application"). The purpose of NPV analysis was to compare the cost of the Project to the cost of capacity and ancillary service purchases from New Brunswick Power Corporation ("NB Power"), despite the latter not being a viable option. The latter option is not viable due to capacity shortages in the region and capacity limitations to the PEI-NB Interconnection ("Interconnection") and NB Power transmission system, as discussed in Section 7.2.1 and Section 7.2.2 of the Application, respectively.

It is also important to note that the Project and the NPV analysis serve to address Maritime Electric's capacity and ancillary needs only. The Company can and will pursue other solutions for energy supply to meet the future needs of customers.

a. Confirmed.

b. Confirmed.

c. Confirmed.

d. The Excel format of the Confidential Appendix E tables is provided confidentially as IR-2d – Confidential Attachment 1.

e. The NPV analysis used capacity and ancillary services pricing for 2024 through 2026 from Maritime Electric's Energy Purchase Agreement ("EPA") with New Brunswick Energy Marketing Corporation ("NBEM") (also referred to as "NB Power" for simplicity), which expires on December 31, 2026. Beginning in 2027, the capacity and ancillary services pricing used in the NPV analysis was inflated using the compound annual growth rate ("CAGR") of capacity pricing from 2019 to 2024 in the NB Power EPA.[2] Maritime Electric also evaluated historical industry cost trends for combustion turbines ("CT"), which were comparable to the NB Power EPA CAGR.[3]

On April 17, 2025, Maritime Electric received indicative market pricing for capacity purchases from 2027 to 2030 that is significantly higher than the pricing used in the NPV analysis.[4] Using this indicative market pricing in the NPV analysis would result in savings greater than the 20 per cent savings included in the Application. The correspondence containing the indicative market pricing is provided confidentially as IR-2e – Confidential Attachment 1.

f. Confirmed.

Transmission tariffs are only applicable to energy imported from New Brunswick ("NB") and, therefore, do not apply to capacity purchased from off-Island. The avoided cost estimations did not consider the cost of importing or of generating energy. These estimations were focused on the cost of capacity and, therefore, the costs of tariffs were not included.

The avoided cost estimations also exclude the costs associated with increasing the transfer capabilities of the Interconnection, which would be required for the avoided cost alternative. Additional information about increasing the transfer capabilities as an alternative to the Project is included in Section 8.1 of the Application.

2 The capacity and ancillary services pricing was inflated using a base year of 2024.

3 Historical cost trends for combustion turbines were from a Handy Whitman Cost Trends of Electric Utility Construction index for "gas turbogenerators."

4 The years 2027 to 2030 are shown as Years 4 to 7 in the NPV analysis.

IR-3 Reference: Portfolios A through D, Section 6.2 of December 2022 report. At page 89 of the December 2022 study, it is stated: "This portfolio was selected due to its ability to most cost effectively meet the three most critical needs of Maritime Electric: …", in regards to Portfolio D.

a. What metrics were used to compare cost-effectiveness across Portfolios A through D?

b. What are the quantitative results of the cost-effectiveness comparison across the four portfolios?

c. Over what time frame is the noted cost effectiveness applicable?

d. Is there any tabulation of the total costs to provide energy and capacity services for Maritime Electric ratepayers for each of the four portfolios? If so, provide those costs. If not, explain why not.

e. Was any explicit production cost modeling of the four portfolios conducted as part of the December 2022 study? If so, please provide the production cost modeling results for each of the four portfolios if not already provided in response to question 1b.

f. The last page of Appendix B to the December 2022 report contains a 20- year comparison of operational costs for a 50 MW BESS unit and a 53 MW RICE unit. What is the purpose of providing this comparison of costs? What are the energy costs (fuel) associated with the RICE resource in the table?

   What is the overall energy cost or benefit effect of the charging and discharging of the BESS resource?

g. If the Capacity Resource Study was limited to comparing the four portfolios listed and described in Section 6.2 of the December 2022 report, provide any additional modeling results and workpapers (in Excel format) associated with each of those portfolios if not already included in the report.

h. Were any other portfolios, besides those four, specifically considered or analyzed? If so, provide such analysis. If not, explain how the specific makeup of those four portfolios was determined for comparison.

Response:

a. The December 2022 analysis was a CRS focused on system reliability planning. Selected technologies were required to provide generating capacity to meet peak demand and respond rapidly during system contingencies such as, curtailments, hold-to-schedule events, peak load conditions or disconnections. The CRS evaluated capital and fixed O&M costs of generation and storage resources to compare portfolio options. Detailed cost data for the CRS is included in the study's appendices. Detailed energy supply models were not generated as these assets are intended primarily for peaking or backup resources (i.e., with limited energy output), and with their limited energy output the cost of energy supply had minimal influence on technology selection.

The capacity to be provided by these resources is essentially needed today, and will remain critical in supporting all future energy supply strategies. Additionally, future energy supplies that include capacity (i.e., baseload generation such as nuclear) would lead the Company to reduce off-Island capacity purchases to accommodate any additional on-Island capacity.

b. Please refer to the response to IR-3(a).

c. The capital and operational costs presented in the December 2022 CRS report reflect conditions at that time. The analysis accounted for the expected operational life of each asset, which varies significantly between generation and storage technologies.[5] Given their intended use as peaking or backup resources with limited energy output, the lifetime energy supply cost had minimal impact on technology selection.

d. Energy and capacity are separate products and are generally not linked, unless the Company financially participates in a project similar to its role in the Point Lepreau Nuclear Generating Station. Please refer to the response for IR-3(a).

e. Please refer to the response to IR-1(b) and IR-3(a). Production cost modeling of the four portfolios was not part of the December 2022 study.

f. As previously noted, the December 2022 analysis was a CRS (not an IRP) with a primary focus on system reliability planning. The referenced comparison table presents fixed O&M costs for both resources, both of which were shortlisted for the analysis. Neither fuel nor BESS charging costs are included in the table as the table compared fixed O&M costs only.

As noted in the December 2022 analysis, a new thermal capacity resource (e.g., RICE and CT resources) would have minimal fuel consumption. For context, Maritime Electric's existing thermal generators operated for less than one hour per month from 2019 to 2023, on average.[6] Historically, these generators supply less than one per cent of Maritime Electric's annual energy supply. These units primarily serve as system backup, along with providing other important system benefits.

The CRS report also explores potential energy sources for charging a future BESS. One option is on-island wind generation; however, current wind capacity is fully utilized in real time, leaving no surplus for BESS charging. Another option is electricity imports from NB Power. Maritime Electric currently procures energy through a fixed-rate contract, which allows hourly scheduling but does not support cost-effective BESS charging due to round-trip efficiency losses. A floating-rate contract could be considered, but it introduces rate volatility risks for customers. Finally, a BESS could be charged from an integrated

5 The expected lifetime for reciprocating internal combustion engine ("RICE") and combustion turbines ("CTs") is 50 years, while the expected lifetime for wind (onshore and offshore), solar, and battery energy storage systems ("BESS") is 20 years.

6 Refer to Table 24, found on page 120 of the Application which shows that over the five-year period between 2019 and 2023 all three of Maritime Electric's CTs operated for a combined total of 123 hours.

marketplace, such as ISO New England ("ISO-NE"); however, Maritime Electric is currently not part of an integrated marketplace. Joining a marketplace and using a BESS resource to pursue an arbitrage strategy would require detailed evaluation.

g. The CRS extended beyond the comparison of four portfolios. Initially, 16 technologies were evaluated. The first screening phase prioritized technologies with substantial industry deployment, minimizing risk exposure, and those for which sufficient renewable resources are available on PEI. This process shortlisted eight technologies.

In the secondary screening, each of the eight technologies was assessed based on their ability to:

- Support Maritime Electric's energy and capacity obligations;
- Operate during electrical disconnection from the mainland; and
- Contribute to Maritime Electric's sustainability objectives.

Six technologies advanced from this phase. The four final portfolios were then selected to represent varying combinations of these six technologies. All portfolio comparison analyses are documented in the CRS report.

h. As noted in the response to IR-1(a), the December 2022 analysis is not an IRP; it is a CRS with a key focus on system reliability planning. Additional portfolios were not considered. As detailed in the December 2022 analysis, six resources were shortlisted for consideration:

- Onshore wind generation;
- Utility-scale solar photovoltaics ("PV");
- Rooftop solar PV generation;
- Energy storage (i.e., lithium ion);
- Reciprocating internal combustion engine ("RICE") with biofuel combustion compatibility; and
- CT with biofuel combustion compatibility.

Of these, only energy storage, RICE, and CT are effective sources of capacity. Each of the portfolios considered included a combination of these capacity resources, in addition to onshore wind and utility-scale and rooftop solar PV resources.

The specific sizes of the capacity resources considered in the December 2022 study were based on Maritime Electric's forecast capacity requirements, while also improving Maritime Electric's ability to serve load in the event of a curtailment or disconnection event from the mainland. The recommended size of the capacity resources was updated in the July 2023 analysis because of the record peak load observed during the February 3 to February 5, 2023 polar vortex event. The size of the wind and solar resources were based on the current outlook of planned generation (via conversations with developers and other sources) at the time of the analysis' publication.

Peak Load and On-Island Capacity Needs – Reference Section 2.2.4 of December 2022 Study

IR-4 Provide annual, historical firm and non-firm import capacity from NB to PEI since the completion of the first two interconnection cables. For each year, include the primary reason for the import capacity limit, e.g., cable capacity, NB transmission concerns, or NB resource availability.

Response:

The requested information is provided in the attachment “Synapse-IR-Responses-in-Excel.xlsx” in the sheet ‘IR-4.’ The values in the spreadsheet represent the firm transmission capacity limits of the total Interconnection, not the actual generating capacity purchased from NB Power.

Before the Interconnection, PEI supplied all its generating capacity on-Island and continued to meet its system peak until approximately 1986. Since then, off-Island generating capacity purchases have gradually increased to about 69 per cent of the system peak in 2023, as referenced in Section 7.6 of the Application.[7] In 2025, NB Power indicated to Maritime Electric that additional generating capacity above the contracted 185 MW is not available for 2025; therefore, the amount of generating capacity available to purchase from NB Power is now the limiting factor for off-Island capacity imports.[8]

Historically, purchasing generating capacity from NB Power resulted in cost savings for Maritime Electric customers because off-Island capacity was more economical than building new on-Island capacity resources. This was due to legacy generation assets providing surplus capacity and a beneficial synergy between the two systems. Regarding the latter, Maritime Electric’s system peak historically occurred the week before Christmas while NB Power’s peak was in January or February, allowing NB Power to have surplus capacity in December. However, with increased use of electricity for space heating on PEI, Maritime Electric’s peak now mostly coincides with NB Power’s peak, which eliminates the capacity synergy.

NB Power no longer has excess capacity to sell to Maritime Electric and plans to add capacity in the form of a 400 MW CT plant near Moncton. Maritime Electric expects the cost of capacity from new mainland-based generation to be similar to new on-Island generation, but off-Island capacity lacks many of the reliability benefits achieved by locating that capacity on-Island.

[7] The ratio of generating capacity purchased from off-Island was offset in 2005 with the addition of CT3 and between 2012 and 2015 with the addition of new generating assets in the City of Summerside.

[8] The generating capacity allotment for Maritime Electric is set in the EPA between Maritime Electric and NBEM. The EPA includes 185 MW of generating capacity for Maritime Electric for the calendar year 2025. The EPA increases this allotment to 190 MW for 2026, the final year of the contract. NBEM have indicated that they will continue to reserve 190 MW of generating capacity for Maritime Electric in the future but no further generating capacity is available.

IR-5 Provide annual, historical On-Island winter peak load (including Summerside) (MW) and on-Island winter capacity resources (including Summerside) from periods starting with the completion of the first two interconnection cables.

Response:

The requested information is provided in the attachment "Synapse-IR-Responses-in-Excel.xlsx" in the sheet 'IR-5.'

Until 2002, Maritime Electric served the City of Summerside ("Summerside") as a wholesale customer, and thus the Summerside load is not shown separately. Since 2002, Summerside has chosen to be responsible for purchasing capacity and energy directly from the mainland, with Maritime Electric providing only transmission service. Maritime Electric's Application for the installation of additional generating capacity is for the supply of Maritime Electric's load only.

IR-6 Provide all underlying Maritime Electric analyses pre-dating the December 2022 Capacity Resource Study of estimating the need for On-Island capacity as a percentage of Island peak load.

Response:

Historically, Maritime Electric has not used the percentage of peak load to determine the amount of generating capacity that should be installed on-Island. Rather, the availability of surplus generating capacity on the mainland and the import capacity of the Interconnection determined the amount of generating capacity required on-Island. The remainder of this response describes how this approach was applied in Maritime Electric's previous two applications to install additional on-Island generating capacity.

Please refer to the sheet 'IR-5' in the attachment "Synapse-IR-Responses-in-Excel.xlsx".

Sheet 'IR-5' shows that the on-Island generating capacity as a percentage of peak load declined steadily after the installation of the first two subsea cables in 1977 until 2004, when it reached 53 per cent. By 2006, the peak load was forecast to exceed the capacity of one subsea cable (i.e., the N-1 criterion, with the largest first contingency being one of the two subsea cables out of service) plus the on-Island generating capacity. In response, Maritime Electric applied to the Island Regulatory and Appeals Commission ("IRAC" or the "Commission") in 2004 for approval to install a 50 MW (49 MW net rating) CT at the Charlottetown Plant site.

Two options were considered in the 2004 CT application: (1) install a 50 MW CT; or (2) install a third cable between NB and PEI. The CT option was assumed to defer the need for a third cable by ten years. It also avoided the purchase of 50 MW of short-term generating capacity from NB Power, which could instead be provided by the 50 MW CT. The CT option had a higher NPV (i.e., a lower cost) and was approved by the Commission.

The 50 MW CT (designated as CT3) was installed in 2005 and increased the on-Island generating capacity to 76 per cent of the system peak.

Sheet 'IR-5' shows that after 2005, the on-Island generating capacity as a percentage of peak load declined to 60 per cent in 2015. In 2015, Maritime Electric applied to the Commission to install an additional 50 MW CT (to be designated as CT4). The need for the CT was based on transmission system constraints in southeastern NB which had limited the maximum firm transmission capacity that was available for deliveries to PEI to 80 MW. This limited the maximum amount of firm generating capacity that could be imported to 80 MW.

Maritime Electric withdrew the 2015 CT application in early 2016 due to: (1) opposition from the Government of PEI ("Government of PEI" or "Province"); and (2) alterations on the NB Power system that led to an upward revision from NB Power on the amount of firm transmission capacity that was available for delivery to PEI.

In 2017, the installation of the third and fourth subsea cables, along with transmission upgrades in both NB and PEI, significantly increased the amount of off-Island generating capacity that could be imported to PEI. Since then, no new dispatchable generation sources have been added on PEI. To meet the increasing demand, Maritime Electric has increased its off-Island capacity purchases each year. In 2022, NB Power began signaling that it was running out of surplus generating capacity. In response, Maritime Electric initiated the development of the CRS, which was completed by S&L and filed with the Commission in February 2023.

IR-7 What is Maritime Electric and S&L's basis for assuming that 50% of winter peak load is a reasonable target for on-Island capacity? Please discuss, and consider the following questions:

a. Is the target of 50% only based on historical trends?

b. Should the target consider 50% of a 50/50 normal peak load forecast, or 50% of the more extreme 90-95% point on a winter peak load forecast distribution (under probabilistic terms)?

c. How should the target consider the potential for AMI-based enabling technologies to significantly reduce peak load, at least for a few hours?

d. Does the target consider the current 4-cable infrastructure level, vs. a historical 2-cable infrastructure?

e. How do N-1, or even N-2, planning standards impact the assessment of a reasonable minimum level of firm import capacity?

Response:

a. Prior to the installation of the first two subsea cables in 1977 that formed the Interconnection, the entire electrical load on PEI was served with on-Island resources. Similarly, many mainland regions across North America have a ratio of over 100 per cent of in-region (i.e., in-province) capacity to peak load.[9]

Industry system planning guidance on PEI's unique situation (i.e., being an interconnected island without a sufficient amount of on-island capacity installed to serve peak load) is limited. As such, the fundamental question around how much backup generation should be installed on PEI must balance reliability risks to the residents of PEI with the cost of the backup generation, noting that any instance of load shedding due to the lack of generating capacity would be an emergency that could have serious consequences. The target of 50 per cent is partially based on the most recent historical trends.

As per Section 7.6 of the Application, the ratio of on-Island capacity to peak system load was approximately 31 per cent in 2023, having fallen below 50 per cent for the first time ever in 2021. A value of 50 per cent would move the system in a direction that would help Maritime Electric better manage a potential curtailment/disconnection event.

b. The 50 per cent target is based on Maritime Electric's capacity requirement, which is discussed in Section 5.3.5 of the Application. The capacity requirement is the 50/50 peak forecast with an additional 15 per cent planning reserve requirement, after controllable demand side management ("DSM") and interruptible customer load is subtracted. Information about the 15 per cent planning reserve is included in Section 5.3.4 of the Application.

[9] As per Table IR-11(b) found in the response to IR-11, PEI is the only province in Canada that does not have sufficient generating capacity located within the province to meet 100 per cent of its peak load.

c. Please refer to the response to IR-7(b) as DSM targets are AMI dependant.

Controllable DSM (i.e., demand response) is subtracted from the 50/50 peak forecast when calculating the capacity requirement. Demand response initiatives consist of eliminating a portion of customer load (i.e., energy consumption) during peak periods. The PEI Energy Corporation's ("PEIEC") Energy Efficiency & Conservation Plan included forecast demand response peak reduction, which was used by Maritime Electric to calculate the capacity requirements.

Maritime Electric is still waiting for details from the PEIEC and efficiencyPEI about specific demand response programs. On February 11, 2025, efficiencyPEI issued a request for proposal ("RFP") for demand response pilot projects. The RFP included suggested program categories of (1) energy storage, (2) interruptible rates and curtailment, (3) dual fuel systems and (4) demand load control systems. Although the RFP is currently only for pilot projects, advanced metering infrastructure ("AMI") is expected to contribute to the success of implementing demand response initiatives.

Even with the proposed addition of 150 MW of on-Island capacity, the Company will continue to rely on NB Power for approximately 190 MW of capacity. This approach ensures that the new capacity remains fully utilized, even if demand response is underestimated or peak load growth falls short of projections. In such scenarios, the Company would simply reduce its dependence on NB Power and related capacity purchases.

Maritime Electric understands that some electric utilities exclude controllable DSM in the capacity requirement calculation and instead consider it as a capacity resource. As such, controllable DSM enabled by AMI can be considered as an on-Island capacity resource and contribute to the 50 per cent target; however, if DSM is considered as a capacity resource, it must not be included in the capacity requirement calculation.

d. There are two primary means by which PEI may be temporarily curtailed or disconnected from the mainland:

1. A technical failure in the Interconnection (e.g., a substation failure, a partial or full subsea cable disconnection or an upstream or downstream transmission line outage); and
2. A capacity shortfall on the mainland (e.g., if NB Power does not have sufficient capacity to supply PEI).

Although the addition of the two new subsea cables in 2017 (cables 3 and 4) provided some additional redundancies, the transmission lines in NB that support the four cables all share a common transmission corridor and terminate at the Memramcook switching station in NB. As such, the 50 per cent target is applicable whether there are two or four subsea cables, especially given the increased likelihood of extreme weather events due to climate change.

On February 10, 2023, Maritime Electric filed a Climate Change Risk Assessment ("CCRA") with the Commission, which was prepared by Stantec Consulting Ltd. ("Stantec"). In the CCRA, Stantec found that "ice storms/freezing rain, hurricanes (tropical storms), and extratropical storms (e.g., Nor'easters) are associated with high risk to the Memramcook substation and transmission lines and towers from the Memramcook to [the subsea cables]". The CCRA identified "increasing backup power generation on PEI" as an adaptation strategy to mitigate this risk.

Furthermore, the additional cables do not address item (2) above. Section 7.2.1 of the Application discussed the capacity shortages expected in the region due to increasing demand and declining availability of capacity. In 2025, NB Power indicated to Maritime Electric that additional generating capacity above the contracted 185 MW in 2025 would not be available.[10]

e. Maritime Electric, in cooperation with NB Power as the regional reliability coordinator, uses N-1 planning criteria to set the import limit on the Interconnection. Although the physical capacity of the four subsea cables is 560 MW, the Interconnection's capacity is limited to 300 MW.

The two 1977 cables are rated at 100 MW each and connect to one transmission line in NB while the two 2017 cables are rated at 180 MW each and connect to their own individual transmission lines. The flow of energy is roughly evenly balanced through the three transmission lines in NB. The N-1 planning criterion considers the loss of the most impactful element, which is either Cable 1 or Cable 2. For example, if Cable 1 trips, one third (1/3) of PEI's import would flow through the remaining Cable 2. If the total import exceeds 300 MW, each of the three remaining cables would exceed 100 MW and Cable 2 would be overloaded. Additionally and coincidentally, the NB-to-NS/PEI interface is restricted to 300 MW of firm transfer due to congestion in the southeastern region of NB and limited reactive power sources, as discussed in Section 7.2.2 of the Application.[11]

[10] The contracted capacity allotment of 190 MW will be provided to Maritime Electric for 2026 and NB Power have indicated that 190 MW would be available beyond 2026 but that no additional capacity would be available until more capacity is built in NB.

[11] PEI is entitled to all 300MW of firm reservation across this interface.

Disconnection or Partial Disconnection of PEI from Mainland New Brunswick

IR-8 Reference: December 2022 Capacity Resource Study, Executive Summary, page III, "… (since 2004, there have been nine times when PEI was either fully or partially disconnected from the mainland)". Section 2.2.3 describes the events in general terms, with limited detail on loss of load specifics.

a. For *each* of the nine events referenced, list the following:

i. the dates,
ii. event duration (hours),
iii. the normal firm interconnection capacity available at the time of the event,
iv. specific cause(s) of the event and preceding steps taken by Maritime Electric, and NB Power, if applicable (e.g., known/anticipated weather)
v. specific level and duration of disconnection (i.e., number of cable or cables disconnected, or other disabling event effect, magnitude of loss of MW import capability, etc.)
vi. loss of load effect on PEI – specific level(s) of MW and MWh loss of load arising from event, and indication if loss of load was interruptible or firm load
vii. status of supply and demand resources on PEI during the event,
viii. description of the resolution of the disconnection event, and
ix. Other factors not included in the above if relevant to the event and its resolution.

Response:

Since 2004, there were four full disconnections and five partial disconnections from the mainland resulting in loss of load. There have also been several partial disconnection events since the 2022 Capacity Resource Study was filed with the Commission, which did not trigger loss of load events but are included at the end of this response. As load continues to grow on PEI, the potential impact of these events will increase.

Information about these events is provided in Appendix A, along with information related to the referenced list, where available.

The most recent full disconnection event occurred on November 29, 2018, for which a detailed report of the event was submitted to the Commission. A copy of the detailed report is provided in Appendix B.

IR-9 Hold To Schedule Section 2.2.3.1 and Table 2-6, Historical CT Operation 2019-2021

a. For the "NB Power "Hold-to-Schedule" table item (2,106 MWh total), the average event MWH is computed as 40.5 (=2,106/52) and the text indicates that events are "typically short in duration (i.e., an hour)". What is the actual range of capacity that has been used for the hold-to-schedule events for the period listed (2019-2021)?

Response:

a. The average, minimum and maximum capacity required for hold-to-schedule events from 2019 to 2023 is provided in Table IR-9(a).

As additional renewable energy projects are added, the capacity required for hold-to-schedule events is expected to increase. Wind energy projects requesting to connect to Maritime Electric's system are shown in Table 2 of the Application and total 136 MW, which is in addition to the existing 203 MW of wind energy currently on PEI (as per Table 1 of the Application).[12] Solar energy projects requesting to connect to Maritime Electric's system are shown in Table 4 of the Application and total 204 MW, which is in addition to the existing 75 MW of solar energy currently on PEI (as per Table 3 of the Application).[13]

Hold-to-schedule events occur throughout the year, including during low-load periods when Maritime Electric typically schedules its CT maintenance. As the capacity required for hold-to-schedule events increases due to additional renewable energy projects, it will become increasingly challenging for Maritime Electric to perform maintenance on its existing CTs. For example, when planned maintenance outages are required for CT3, only 40 MW of total dispatchable generating capacity remains from CT1 and CT2.

TABLE IR-9(a)
Historical Hold-to-Schedule Capacity Requirements (MW)

	2019	2020	2021	2022	2023
Average	19	29	34	20	20
Minimum	4	22	15	6	5
Maximum	41	41	64	37	41

12 Table 2 is on page 22 and Table 1 is on page 21.
13 Table 4 is on page 27 and Table 3 is on page 26. Existing 54 MW of solar energy includes 44 MW of net-metering solar.

IR-10 Reference: Historical Frequency of Mainland Disconnections, Section 2.2.3

a. Has Maritime Electric or S&L conducted any probabilistic analysis of the chance of partial or full disconnection of the import capacity from NB? If so, provide such analysis.

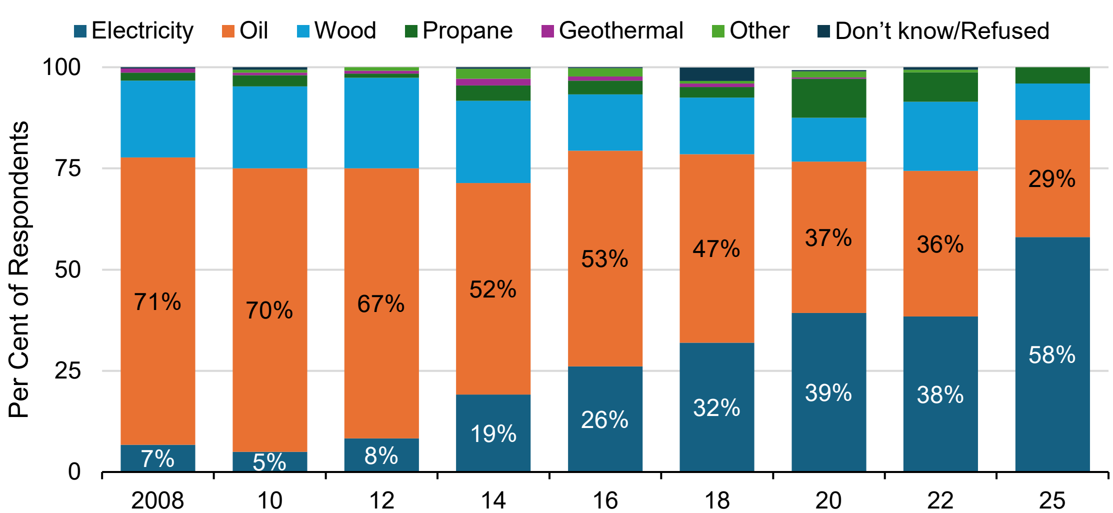
Response:

a. Neither Maritime Electric nor S&L has conducted such analysis.

As discussed in the response to IR-8, there were nine full or partial disconnection events of the Interconnection since 2004. The probability of full and partial disconnection events occurring is low but the potential consequences are high, given the increasing number of customers using electricity for heating.

Figure IR-10 is an update to Figure 12 from the Application that shows primary heating systems on PEI with the addition of 2025 actuals. The updated 2025 data shows that 58 per cent of PEI residents now use electricity as a primary heat source. This increase in electric space heating increases the risk of full and partial disconnection events. Additionally, as discussed in response to IR-7(d), extreme weather due to climate change presents increasing risk of damage to the above ground Interconnection assets in NB and PEI, including substations and transmission lines.

FIGURE IR-10
Update to Application Figure 12
PEI Primary Heating Systems with 2025 Results



Data source: Government of PEI. Home Heating Surveys.

IR-11 Mandated Reliability Requirements Under NERC or NPCC or NB Power.

a. What is Maritime Electric's reliability requirement under NERC and/or NPCC guidelines, or NB Power control area requirements, with respect to maintaining resource adequacy on PEI (or within Maritime Electric's service territory on PEI) under an event with complete or partial disconnection of import capacity from New Brunswick? Discuss the nature of the specific on-Island capacity MW obligations Maritime Electric is under for conditions of complete or partial disconnection.

b. Is it Maritime Electric's position that the decision to require some minimum level of On- Island capacity is based on PEI's needs and assessments of economic loss under loss of load conditions, or based on minimum requirements under certain NERC or NPCC or NB Power guidelines or mandates, or something else?

Response:

a. While Maritime Electric is not mandated to comply with NERC or Northeast Power Coordinating Council ("NPCC") standards, the Company voluntarily aligns with key elements of these and other relevant electric utility standards. Under the PEI *Electric Power Act*, Maritime Electric is obligated to provide service to all customers within its jurisdiction. Section 39 of the Act states:

> *If the supply of electric energy from any public utility to its customers is interrupted for any continuous period exceeding fifteen minutes, except in any case approved by the Commission, and the Commission upon investigation, finds that the interruption of supply or service was due to circumstances which the public utility, by the exercise of reasonable care and foresight, could have avoided, the Commission may impose upon the public utility a penalty not exceeding $5,000 for each interruption...*

Maritime Electric takes this service obligation seriously. While full or partial disconnections from the mainland are rare, significant curtailments occur more frequently. As more Islanders transition to electricity as their primary source of space heating, it is critical that Maritime Electric maintain the ability to serve customers during such events. Increasing on-Island dispatchable generation enhances this capability and provides other important system benefits, as outlined in the Application.

Maritime Electric also operates under an Interconnection Agreement with NB Power. This agreement includes a 15 per cent planning reserve requirement for capacity for Maritime Electric but does not specify the geographic source of that capacity. Further details are provided in Section 5.3.4 of the Application.

b. Maritime Electric is not aware of any requirements under NERC, NPCC or through NB Power that specify a minimum level of on-Island generating capacity. The appropriate amount of in-province (i.e., on-Island) capacity is based on several factors that are unique to each jurisdiction. Maritime Electric believes that the appropriate amount of on-Island generating capacity should be based on the risks associated with increased dependance on off-Island capacity resources, which are discussed in Section 7.2 of the Application.

Compared to other jurisdictions in Canada, PEI is heavily reliant on off-Island (i.e., out-of-province) capacity resources to serve its system peak. Table IR-11(b) compares the ratio of in-province capacity resources to peak load across Canada. The table shows that PEI has significantly less in-province capacity to serve its peak load (32 per cent) compared to other provinces, which all have sufficient in-province generating capacity to meet over 100 per cent of their peak load.

TABLE IR-11(b)[a]
Estimated Ratio of Capacity to Peak Load for Canadian Provinces

Province	Peak Load (MW)	Dispatchable Generating Capacity (MW)	Wind		Total Generating Capacity (MW)	Capacity to Peak Ratio (%)
			Nameplate Capacity (MW)	Estimated ELCC[b] (MW)		
Alberta	12,384	13,515	3,749	937	14,452	117%
British Columbia	11,300	17,509	702	175	17,684	156%
Manitoba	5,112	6,535	259	65	6,599	129%
New Brunswick	3,326	4,429	329	82	4,511	136%
Newfoundland	1,765	8,628[c]	54	14	8,642	490%
Nova Scotia	2,455	2,535	603	151	2,686	109%
Ontario	27,005	30,389	5,575	1,394	31,783	118%
PEI	**395**	**109[d]**	**203**	**30[e]**	**139**	**35%**
Quebec	43,124	42,715	4,563	1,141	43,856	102%
Saskatchewan	3,910	4,299	1,689	422	4,721	121%

a. Data for all provinces other than PEI was taken from the Canadian Energy Regulator website - https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA.
b. The wind effective load carrying capability (“ELCC”) in Table IR-11(b) is estimated at 25 per cent of the nameplate capacity for all provinces other than PEI.
c. Most of the approximate 5,400 MW of capacity from Churchill Falls Hydro Generation is sold to Quebec.
d. The dispatchable generating capacity for PEI includes 89 MW for Maritime Electric and 20 MW (15 MW of RICE and 5 MW BESS) for the City of Summerside.
e. The wind resources included for PEI include wind resources not under contract with Maritime Electric and therefore not considered in previous ELCC calculations. As per figure 8 of the Application, the expected ELCC for 203 total MW of wind on PEI is approximately 30 MW.

Cost Estimates

IR-12 Reference: Application and Evidence, page 7, and cost estimates, Table 13, page 62. At page 7 it states that the cost estimate "does not include inflation or cost changes due to market dynamics between 2024 and the time of construction". At page 128 of the Application and Evidence, Maritime Electric states "The factors that will influence the estimated impact on rate base, revenue requirement and customer rates include…the impact of CT and RICE equipment market pricing dynamics in a period of high demand".

a. Since the last assessment of CT and RICE equipment costs, how has Maritime Electric or S&L directly considered increasing upward cost pressures on CT and RICE equipment given the market effects associated with the North American demand increases from data center load forecasts?

b. What is Maritime Electric or S&L's current estimate of the cost of CT or RICE technologies?

c. The Application and Evidence refers to the December 2022 Capacity Resource Study, which contains an estimate for a 50 MW, 4-hour BESS resource of $2,670/MW. While Appendix A of the Application and Evidence contains an updated BESS cost, it is only for a 10 MW, 4-hour BESS resource. What is Maritime Electric's or S&L's current estimate of the cost of a 50 MW, 4-hour BESS resource?

d. How has Maritime Electric or S&L considered the effect of scale (i.e., 50 MW vs. 10 MW) on per unit costs for BESS resources? Would Maritime Electric expect per unit costs for BESS technologies at a 50 MW scale, vs. a 10 MW scale, to be lower? If so, by how much? If not, why not?

e. Has Maritime Electric considered the potential cost contribution or financing cost reduction for BESS resources under Canada's SREP (Smart Renewables and Electrification Pathways) program?

   i. If so, what effect would the SREP options have on BESS resource costs to Maritime Electric ratepayers?
   ii. If not, why not?

Response:

a. As indicated in Section 6.4.2 of the Application, Maritime Electric is aware of the present upward cost pressures on CT and RICE equipment due to high global demand. Maritime Electric also receives periodic market status updates from S&L, which is currently working on more than two dozen active generation projects using CT and RICE technology and has first-hand knowledge of current market conditions. Currently, the main drivers affecting the global demand of CT and RICE equipment are:

- The retirement of coal power plants being replaced with efficient gas turbine combined cycle plants;
- An increased penetration of renewable energy penetration requiring new reliable

dispatchable generation to balance the system; and
- Significant electricity demand growth due to data centers, industrial facilities, and overall electrification of the economy.

b. Based on similar equipment configurations and equivalent contingency allowances included in the original cost estimate, the current estimated overnight capital costs are equal to:

- 50 MW CT: $197.8 million or $3,871 CAD/kW;[14] and
- 90 MW RICE plant: $291.2 million or $3,234CAD/kW.[15]

Note that these values do not include considerations for cost components such as inflation, financing fees or interest during construction, tariffs, land acquisition, network upgrades or Interconnection facility costs, and/or high voltage transmission line construction.

TABLE IR-12(b)
Updated Project Component Cost Estimates

Unit	Application (2024) (CAD/kW)	Current (2025) (CAD/kW)	Change (%)
1 x 50 MW GEV LM6000 CT with synch condenser	3,345	3,871	+16%
5 x 18 MW Wartsila RICE units	2,722	3,234	+19%
10 MW/40 MWh BESS (lithium ion)	2,664	2,670	-

c. Based on similar equipment configurations and equivalent contingency allowances to that of the prior assessment for the BESS case, the current estimated overnight capital costs for a 50 MW/200MWh BESS are equal to $111.7 million or $2,234 CAD/kW. Note that these values do not include considerations for cost components such as inflation, financing fees or interest during construction, tariffs, land acquisition, network upgrades or Interconnection facility costs and/or high voltage transmission line construction.

However, as per Section 8.3 of the Application, a 50 MW/200 MWh BESS cannot be counted as a 50 MW capacity resource. A 50 MW BESS would require substantially more storage to allow it to count as a 50 MW capacity resource.

d. S&L expects that the cost of constructing a 10 MW/40 MWh BESS would be more expensive on a levelized per-kW basis compared to a similarly configured 50 MW/200 MWh BESS. Based on a similar project configuration and equivalent contingency allowance provided in the original cost estimate, S&L expects an estimated overnight capital cost for a 10 MW/40 MWh BESS to be equal to $26.7 million or $2,670 CAD/kW. It is noted that a BESS of this size may not require substation and high voltage work to the extent required for the development of a 50 MW BESS project; however, additional analysis is required.

[14] Based on 1 x GEV LM6000 Aeroderivative Combustion Turbine (estimated at 51 MW gross output). Currency is CAD based on an exchange rate of 1.38 CAD/USD.
[15] Based on 5 x 18 MW Wartsila RICE units. Currency is CAD based on an exchange rate of 1.38 CAD/USD.

e. Please refer to response to IR-18. Maritime Electric has applied for Smart Renewables and Electrification Pathways ("SREP") funding.

i. If Maritime Electric was successful in securing SREP funding for the BESS or any other components of the Project, the funding would fall under a contribution in aid of construction and directly reduce the project cost.

Wind Performance Synergies – Wind Energy and Battery Storage on PEI/Performance going forward

IR-13 Reference: December 2022 report, at page 11. Maritime Electric estimates that without CT3 online during a disconnection event, wind resources might not be able to assist at all ("…thus , an estimated 0% of the on-island wind generation could be utilized without risking system collapse"). With an increased level of BESS resources on-island, wouldn't the system collapse risk be much lower, thus always enabling wind resources to contribute to energy and capacity needs during a disconnection event? Please discuss.

Response:

During a disconnection event, PEI would be operating as a power system island, also known as "Islanded Operation". During Islanded Operation, on-Island generation sources must provide the required inertia, voltage support, short circuit current, capacity reserve, and other power system support services. These services are essential to provide safe and reliable electricity on PEI during Islanded Operation. The existing wind and solar farms on PEI are not designed or configured to provide these services; as such, it is critical that traditional generation, such as CT3, be online to support the power system during Islanded Operation.

Further to this, for wind or solar farms to operate, the transmission system must be energized. To energize the transmission system, the above services are required to ensure the lines operate in a safe and reliable manner. To discuss one of many risks, without traditional generation online, there may not be enough short circuit current available to enable the protection system to operate reliably. This may result in a normal fault not being detected and isolated from the system, creating a dangerous situation for the public. The addition of battery, wind, or solar generation resources is not expected to mitigate these concerns.

IR-14 What specific steps has Maritime Electric taken since the February 2023 extreme weather event to address the performance of wind power resources on PEI, either those contracted directly to Maritime Electric or contracted for delivered of power off-Island?

Response:

Maritime Electric does not own or operate any of the wind turbine resources on PEI and thus does not have direct control over upgrades and repairs to those resources. However, Maritime Electric held meetings and requested information from various PEI wind farms related to addressing their performance during cold weather events.

In general, there were three reasons why some wind turbines did not perform well during the polar vortex weather event between February 3 and 5, 2023: (1) extreme cold; (2) high winds; and (3) grid stability. These three reasons and actions being taken to address them are summarized below.

1. Extreme Cold

   Some wind turbines shut down as they exceeded their minimum cold temperature ratings. The existing wind turbine models on PEI have minimum operating temperature ratings in the range of -20 degrees Celsius (“°C”) to -30°C; however, prior to the polar vortex weather event, some turbine blade collars (i.e., rain shields) were damaged and removed, which may have contributed to wind turbines shutting down despite temperatures being within their operational ratings. The associated wind turbine operators have been working to repair the damaged blade collars and will prioritize the replacement of blade collars during the summer period (i.e., prior to cold weather) in the future.

   Some wind turbine operators have also suggested prematurely operating heaters within the wind turbine nacelles, and staffing wind farms 24/7 for immediate response to shutdowns when extreme cold weather is forecast, as proactive solutions for extreme cold operations.

   The new PEIEC wind farm currently under construction (Eastern Kings Phase 2) will have minimum temperature ratings of -40°C, a significant improvement over the existing wind turbines on PEI.[16] They will also feature blade heaters that will help operation through freezing rain events.

2. High Wind

   Some wind turbines shut down due to exceeding their maximum wind speed ratings. The existing wind turbine models on PEI have maximum operating wind speeds of 76 km/h to 104 km/h. In cases where the wind turbines shut down for a prolonged period, the extreme cold weather sometimes impeded their ability to restart.

   There are no practical solutions to protect wind turbines from high winds; however, it is rare that wind speeds are above maximum operating levels during extreme cold weather. Staffing the wind farms 24/7 during extreme cold weather may help restart the turbines quickly before they get too cold, if the wind speeds subside.

[16] The wind turbines may experience up to 25 per cent reduced output between -30°C and -40°C.

3. Grid Stability
Some wind turbines shut down due to low voltage faults. Previously planned Maritime Electric projects, such as the Woodstock substation, will strengthen the grid in Western PEI and help prevent some of these faults from occurring for wind farms in this area. Staffing the wind farms 24/7 may also help restart the turbines quickly before they get too cold, as the grid stability issues are only momentary.

IR-15 S&L noted in the July 2023 report that "S&L recommends further information sharing and/or a technical conference, between Maritime Electric, the wind operators, and the wind generator original equipment manufacturers to fully understand what transpired and find solutions to prevent a repeat of the changes experienced between February 3 and 5, 2023".

a. Was a technical conference or similar forum held to fully understand the circumstances and find solutions to the performance issues of February 3-5, 2023?

b. If so, what was the result of that conference or forum, and what steps are currently underway to ensure improved performance of the wind resources?

c. If not, why not?

d. What is Maritime Electric's current planning assessment – i.e., Maritime Electric's current assessment of expected wind turbine operation - for wind resources on PEI during extreme winter weather events?

Response:

a. An official technical conference was not held with the wind farm operators; however, individual meetings were held with each wind farm operator independently throughout 2023, 2024 and 2025. Additionally, a separate discussion was held at a Maritime Electric Transmission Users Group Meeting on January 23, 2025. The results of these conversations are presented in the Company's response to IR-14. Maritime Electric is satisfied that on-Island wind farm operators are taking positive steps towards increasing the reliability of on-Island wind production during extreme weather events.

Maritime Electric is pleased with the PEIEC decision to purchase a new type of wind turbine for their upcoming Eastern Kings Phase 2 project which will have significant improvement in extreme weather operation over the existing wind turbines on PEI.

b. Please refer to the response to IR-14.

c. Individual meetings were held with each wind farm operator on PEI and the Transmission Users Group meeting discussed in response to IR-15(a) effectively served the function of the technical conference. Maritime Electric was satisfied with the steps being taken to improve the wind farms' operation during cold weather.

d. Based on the information provided by wind farm operators on PEI, most PEI wind farms are now believed to be well positioned to maintain operation during extreme cold weather events such as the February 3 to 5, 2023 polar vortex.

Maritime Electric continues to use the ELCC of wind to determine the amount of nameplate wind capacity that can be counted towards the Company's capacity requirements, as discussed in Section 5.1.2 of the Application.[17] In 2023, the year during which the polar

[17] Information about the ELCC of wind begins on line 9 of page 24 of the Application.

vortex weather event occurred, the ELCC of wind was 23 MW. Despite the poor performance of some wind turbines during the polar vortex event, there was approximately 26 MW of wind production at the time of the February 4 peak; this is slightly more than the ELCC. As a result, and given the steps taken to address the performance of wind turbines as discussed in response to IR-14, Maritime Electric believes that its current use of the industry standard ELCC of wind is acceptable.

Additionally, Maritime Electric's capacity requirement includes a 15 per cent planning reserve that provides contingency for events such as capacity resource failures, including wind turbines. It is important that Maritime Electric maintains the 15 per cent planning reserve for this purpose.

AMI

IR-16 Reference: Application and Evidence, pages 41-44, including Capacity Requirements Forecast Table 9.

a. Confirm, or explain otherwise, that potential winter peak load reductions from demand response resources associated with the planned implementation of advanced metering infrastructure (AMI) is fully excluded from the Capacity Requirements Forecast of Table 9.

b. What is Maritime Electric's expectation for potential peak load reductions from the planned AMI installations for the years following completion of the AMI project?

c. How has Maritime Electric quantitatively considered the potential for increased levels of peak load reduction from utilization of AMI coupled with enabling technologies to result in materially significant increases in "controllable DSM" during emergency periods of extreme winter weather (Application, page 42, "Examples of controllable DSM programs include incenting the installation of controllable water heaters and heating system thermostats, which can be controlled by the electric utility during system peaks")?

Response:

a. Incorrect. Please refer to response to IR-7(c).

The "Controllable DSM" listed in Table 9 of the Application represents demand response initiatives. Currently, energy efficiency and controllable DSM initiatives, including demand response technologies, are coordinated and administered by the Government of PEI. AMI is expected to enable the use of the demand response technologies introduced by the Government of PEI.

b. Time of Use ("TOU") rates is an example of an innovative rate structure enabled by AMI that can result in peak reduction by incentivizing customers to shift load from peak to off-peak periods. Dunsky Energy Consulting's Prince Edward Island Efficiency Potential Study (Volume I) ("Dunsky Study") commissioned by efficiencyPEI found that "PEI's [electricity] system has a relatively flat load curve with an evening peak as well as a second peak in the morning," and, therefore, "[peak shifting] measures with significant bounce-back or pre-charge effects close to the peak will likely have limited potential to reduce the annual peak…"[18] Since the Dunsky Study was completed, Maritime Electric has observed growth in the morning peak due to the continued electrification of space heating. In fact, two of the last five annual peaks occurred during the morning. The growth of the morning peak has further limited the potential to reduce the annual peak with peak shifting measures. The Dunsky Study, at the time of publication in 2021, projected that TOU rates could achieve a PEI total peak reduction of 10.7 MW, which represents only a 2.8 per cent reduction relative to the peak of 381 MW (PEI total) experienced in January 2025.

[18] Dunsky Study page 56.

In Maritime Electric's amended and re-stated Supplemental Capital Budget Request Application for the Advanced Metering for Sustainable Electrification Project (Docket UE20737), the Company included a Reduced Peak Demand benefit which was based on the implementation of TOU rates. This benefit included a 2.63 per cent peak reduction attributed to TOU rates.[19] In that application, the Reduced Peak Demand benefit allowed for a 11.2 MW (2.63 per cent of 424 MW) peak load reduction.

Additional peak load reduction may be possible through the use of critical peak pricing ("CPP") which is typically an opt-in program that sends a strong price signal to customers to reduce load on a small number of critical peak days.[20] This type of incentive can reduce peak demand beyond what is achievable through TOU rates, as it can eliminate load during the critical peak days. It is important to note that the programs proposed in efficiencyPEI's RFP (e.g., load control systems and curtailments) are, in effect, the same as CPP (please refer to IR-7(c)). The load reductions from efficiencyPEI's DSM programs may compete with load reductions possible through the use of CPP.

c. Please refer to Response to IR-7(c), Response to IR-16(a) and Response to IR-16(b).

Forecast peak reductions from controllable DSM are already included in Maritime Electric's capacity requirements forecast. The annual forecast for controllable DSM is shown in Table 9 of the Application is based on the implementation of energy efficiency and controllable DSM initiatives, including demand response technologies, coordinated and administered by the Government of PEI. AMI is expected to enable the use of the demand response technologies introduced by the Government of PEI.

To the extent that reductions in peak load are achieved through DSM, demand response and TOU rates, the result would be a modest reduction in the amount of short-term capacity purchases from NB Power.

[19] Miller, Reid, et. al. "Modelling weather effects for impact analysis of residential time-of-use electricity pricing." Energy Policy, Volume 105, 2017. https://doi.org/10.1016/j.enpol.2017.03.015

[20] Nova Scotia Power recently launched an opt-in CPP rate pilot which reduces the residential rate of $0.18561/kWh to $0.15852/kWh for all hours outside of CPP events for participating customers. However, during CPP events pricing is $1.70940/kWh. CPP events last four hours, and participants will be notified by email and/or text message by 4:00 pm the day prior. Up to a maximum of 18 peak events could be called between November 1 and March 31. These events can only be called on weekdays and up to three on weekends (statutory holidays are excluded).

Canadian Federal Issues

IR-17 Reference: NS-NB approved new 345 kV transmission intertie in 2028/2029, and impact on NB-PEI capacity import reliability.

a. In what way has Maritime Electric or S&L considered or accounted for the planned 2028/2029 completion of the second 345 kV tie between Nova Scotia and New Brunswick when considering the availability and cost of capacity and energy for import to PEI from New Brunswick?

b. In what way has Maritime Electric or S&L considered or accounted for the planned 2028/2029 completion of the second 345 kV tie between Nova Scotia and New Brunswick when considering the relative reliability of the transmission system in New Brunswick and its effect on PEI capacity and energy import availability and reliability during times of highest system stress?

Response:

a. The NS-NB 345 kV intertie will provide an additional 345 kV transmission line between Salisbury, NB and Onslow, NS and will connect to the Memramcook station, which is located between Salisbury and Onlsow. The limited availability of capacity in NB is not a function of transmission capacity but rather a lack of installed generation capacity in the region. As such, the new line is not expected to change the amount of capacity available for import to PEI. Should generation capacity be added to the NB or regional systems, the cost of such capacity that would be available to PEI will be influenced by the cost of the new additions.

The new line will increase the reliability of the transmission system in southeastern NB and northern NS but will not increase the available transfer capability to PEI from NB. A shortage of reactive power support in southeastern NB limits the amount of energy that can be delivered to PEI and NS across the NB-to-PEI/NS interface. A second phase of this project, adding a 345 kV transmission line between Salisbury, NB and St. John/Pt. Lepreau, NB and increasing reactive power support in the Moncton area is required to relieve this condition. As such, the addition of a second 345 kV transmission line between NB and NS will not increase Maritime Electric's ability to procure energy from NB during periods of high load.

b. The new line will improve the reliability of the Memramcook station but will not improve the reliability of the Interconnection itself, as the line is upstream of the Interconnection. The new 345 kV line does not provide an additional path to PEI and will not increase the available transfer capability to PEI from NB. Additional system upgrades are required in both the NB and PEI systems to facilitate an increased available transfer capability.

IR-18 Reference: SREP (Smart Renewables and Electrification Pathways) program – funding for utility-scale battery energy storage. Maritime Electric has obtained Canadian Federal funding through the SREP program for a planned AMI system in its service territory on PEI. Nova Scotia Power has obtained SREP funding for 150 MW of utility-scale battery energy storage systems to facilitate wind energy integration in Nova Scotia.

a. Has Maritime Electric considered or discussed with Canadian Federal entities the potential to use SREP funding in support of installation of battery energy storage facilities on PEI?

   i. If so, describe the current status of such discussions, including any information available on the impact of the cost reduction of BESS systems available under SREP.
   ii. If not, why not?

Response:

a. Yes, Maritime Electric has applied for SREP funding.

   i. On December 13, 2024, Maritime Electric submitted an expression of interest application for SREP funding (utility support stream deployment projects) to the Government of Canada. The SREP application included the installation of a 10 MW/40 MWh BESS. On February 21, 2025, Maritime Electric was notified by the Government of Canada that it was not selected to proceed to the next stage of the funding evaluation process.

   Additionally, on April 30, 2025, Maritime Electric submitted a letter of interest to the Government of PEI to be considered for a proposal to Natural Resources Canada ("NRCAN") for a Distributed Energy Resources Potential Studies funding stream. Only work related to studies of the 10 MW/40 MWh BESS is eligible for funding under this program. Maritime Electric is waiting for a response from the Province regarding the funding.

   Maritime Electric continues to seek eligible funding opportunities for the Project and will update the Commission if it is successful in being awarded funding.

IR-19 Reference: Figure 1 of April 23, 2025 filing (capacity balance): Please provide hourly data from December 1, 2024 through March 31, 2025 (in Excel format) listing Maritime Electric load and resources used to meet those hourly loads (NB firm, NB non-firm, PEI wind, Maritime Electric CTs, Pt. Lepreau, other). If such data is available for all of PEI (inclusive of Summerside), please also provide the broader set of the same information. If available, please indicate what the NB-to-PEI import capacity was in total for each of the hours listed.

Response:

The requested information is provided in the attachment "Synapse-IR-Responses-in-Excel.xlsx" in the sheet 'IR-19.' The data is approximate and is rounded to the nearest MW.

Column 'Q' (Maritime Electric Imports NB-PEI Intertie Hourly Average MW) represents Maritime Electric's contractual imports from NB to PEI from Point Lepreau and NB Power. Column 'R' (NB-PEI Physical NB-PEI Intertie Hourly Average MW) represents the actual intertie (i.e., physical energy flow) between NB and PEI. The difference between the contractual and physical intertie amounts is the energy imported for Summerside and exported from the West Cape wind farm.

With regards to the request for load and energy supply data inclusive of Summerside, it is important to clarify that the Application is specifically focused on Maritime Electric's operations and capacity requirements. Summerside operates as a separate electric utility, and as such, Maritime Electric believes that it is not within its purview to provide operational data for Summerside.

APPENDIX A

Full and Partial Disconnection Events

For each of the full or partial disconnection events listed, the following information is provided:

i. Event date(s);
ii. Event duration (hours);
iii. The normal firm interconnection capacity available at the time of the event;
iv. Specific cause(s) of the event and preceding steps taken by Maritime Electric, and NB Power, if applicable (e.g., known/anticipated weather);
v. Specific level and duration of disconnection (i.e., number of cable or cables disconnected, or other disabling event effect, magnitude of loss of MW import capability, etc.);
vi. Loss of load effect on PEI – specific level(s) of MW and MWh loss of load arising from event, and indication if loss of load was interruptible or firm load;
vii. Status of supply and demand resources on PEI during the event;
viii. Description of the resolution of the disconnection event; and
ix. Other factors not included in the above if relevant to the event and its resolution.

Full Disconnections from the Mainland (since 2004)

April 28, 2004
A 69 kV transmission line in Moncton (line L24) tripped instantaneously due to a fault when a phase of a 138 kV Salisbury-Memramcook/tap to Moncton (L1190/1124) sagged close enough to initiate an arc between the two lines. The trip of L24 extinguished the fault (because it isolated L24 from a ground reference via the 138/69 kV Moncton tie transformers) but it left L24 energized at higher-than-normal voltage because of continued arcing from the 138 kV line. About a half-second later, it appears that this high voltage caused a 69 kV lightning arrester at Gayton substation on L24 to fail, resulting in a blown 69 kV fuse at the substation that cleared this fault. This second fault also triggered the Memramcook protection on L1190 to open that end of the 3-terminal 138 kV line. Due to the breaker configuration at Memramcook, this action caused both Memramcook L1142 (to Murray Corner) and Memramcook L1160 (to Springhill, Nova Scotia) to open. With L1143 (to Murray Corner) already out of service due to the switching carried out on Monday, April 26, 2004, the opening of L1142 cut off supply to PEI and triggered an automatic protection system that used teleprotection to immediately trip both 138 kV subsea cables that had been supplying PEI. With no generation on-line, an Island-wide outage occurred on PEI.

i. April 28, 2004.
ii. 0.93 hours.
iii. 117 MW.
iv. Fault on 69 kV transmission line L24 in New Brunswick. No preceding steps were taken by Maritime Electric or NB Power as not weather related and no warning.
v. Both subsea cables in-service at time of event (Cable 1 and Cable 2) were disconnected. With no generation on-line, an Island-wide outage occurred on PEI.
vi. An Island-wide outage was experienced – approximately 147 MW of load.
vii. No conventional generation was on-line on PEI (40 MW combustion turbines (“CTs”) available in Borden, 65 MW Steam Plant available in Charlottetown). All wind generation and all load were lost during the event.
viii. Description provided above.
ix. This event occurred more than 21 years ago. Specifics of the requested details of the event are difficult to find.

May 21, 2005

Failure with a tap changer on the X-6 autotransformer in the West Royalty substation resulted in an initial outage to 51,670 PEI customers. While restoring power to the system, a low voltage condition on the system resulted in the low voltage protection scheme initiating and tripping the two 138 kV cables connecting PEI to the New Brunswick electrical grid, resulting in an Island-wide outage for PEI.

i. May 21, 2005.
ii. 0.50 hours.
iii. 100 MW.
iv. Fault in tap changer in X-6 autotransformer. No preceding steps were taken by Maritime Electric or NB Power as not weather related and no prior warning.
v. Both subsea cables in service at time of event (cables 1 and 2) were disconnected.
vi. An Island-wide outage was experienced. No load data available for the time.
vii. No conventional generation was on-line on PEI (40 MW CTs available in Borden, 65 MW of Steam Plant available in Charlottetown). All wind generation and all load were lost during the event.
viii. Description provided above.
ix. This event occurred 20 years ago. Specifics of the requested details of the event are difficult to find.

September 19, 2007

A large potato sprayer, which was being operated in potato fields in the Searletown Road area of PEI, caused a severe flashover on the 138 kV overhead transmission line (Y-101) due to the sprayer coming too close physically to the line. The fault occurred about 3.9 kilometres (“km”) away from the Bedeque substation. The neutral over-current relaying protection on transmission lines L1142 and L1143 in Memramcook, New Brunswick, operated and timed-out after two seconds. A direct trip tone was sent to Murray Corner and it tripped all the breakers resulting in an Island-wide outage for PEI while the interconnection load was about 150 MW.

i. September 19, 2007.
ii. 2.5 hours.
iii. 160 MW.
iv. Line-to-ground fault on Y-101 transmission line between Richmond Cove and Bedeque Switching Station due to flashover to potato spraying equipment. No preceding steps were taken by Maritime Electric or NB Power as not weather related and no prior warning.
v. Both subsea cables in-service at time of event (cables 1 and 2) were disconnected.
vi. An Island-wide outage was experienced. Approximately 150 MW.
vii. No conventional generation was on-line on PEI (40 MW of CTs available in Borden, 65 MW of Steam Plant available in Charlottetown). All wind generation and all load were lost during the event.
viii. Description provided above.
ix. Not applicable.

November 29, 2018

A weather event involving heavy wet snow, ice and high winds moved through the Maritimes area on the night of November 28, 2018, and into the morning of November 29, 2018. The accumulation of wet snow and ice on transmission conductors and overhead ground wires resulted in many sustained transmission outages.

Five transmission lines connecting Cape Breton Island to the Nova Scotia mainland tripped over a period of several hours (some lines tripped multiple times before permanently faulting). This caused a surplus of power in Cape Breton and a deficit of power on the mainland. Excess power in Cape Breton caused frequency to rise until several coal plants, hydrogeneration and two small wind farms tripped due to operator intervention or over-frequency protection. The Maritime Link high voltage direct current ("HVDC") interconnection with Newfoundland also tripped due to sustained high frequency.

The Nova Scotia Power Inc. ("NSPI") System Operator took action to limit the load on the intertie to keep it within limits (300 MW). This was accomplished through the curtailment of interruptible loads and manual load shedding. Throughout the morning two 138 kV and one 345 kV transmission line tripped in the NB/NS/PEI interconnection leaving only three 138 kV transmission lines into Memramcook, resulting in loading on the remaining transmission lines exceeding seasonal operational limits. At 8:58 a.m. the temperature of the conductor on one of the remaining transmission lines reached 100°C causing the Thermal Overload Special Protection Scheme ("SPS") to operate as per design. The SPS operation tripped all four cables, separating PEI from NB electrically and causing an Island-wide outage for PEI. This operation also inadvertently separated NB from NS due to the abnormal storm related configuration of the busses in Memramcook.

i. November 29, 2018.
ii. 8.5 hours.
iii. 240 MW.
iv. Failures of multiple transmission lines in Nova Scotia and New Brunswick causing a cascading overloading of transmission lines feeding the Memramcook Switching Station thus causing the Thermal Overload SPS to operate, separating PEI from NB electrically. Maritime Electric staffed-up Energy Control Center in early morning hours of November 29 in anticipation of events relating to freezing rain weather in NB and PEI.
v. All four subsea cables in-service at time of event (cables 1, 2, 3, and 4) were disconnected.
vi. An Island-wide outage was experienced. The loss of load was approximately 240 MW.
vii. No conventional generation was on-line on PEI (40 MW of CTs available in Borden, 50 MW of CTs available in Charlottetown, 50 MW of Steam Plant available in Charlottetown).
viii. Description provided above.
ix. Not applicable.

Partial disconnections from the Mainland resulting in loss of load (since 2004)

May 6, 2008
Cable 1 tripped due to a fault in reactor 1 in the Bedeque switching station. Cable overload scheme was automatically initiated to ensure overloading of Cable 2 did not occur for a prolonged period of time. Combustion turbine generation was automatically started.

i. May 6, 2008.
ii. 5.5 hours.
iii. 160 MW.
iv. Fault in Reactor 1. No preceding steps were taken by Maritime Electric or NB Power as not weather related and no prior warning.
v. Cable 1 tripped.
vi. Cable overload scheme automatically initiated which shed approximately 20 MW of interruptible customers load.

vii. 40 MW of CTs available in Borden; 50 MW of CTs available in Charlottetown; 57 MW of Steam Plant (in cold lay-up) available in Charlottetown.
viii. Description provided above.
ix. Not applicable.

March 7, 2011
Cable 2 tripped due to a fault in the circuit switcher for Reactor 2. Cable overload scheme was automatically initiated to ensure overloading of Cable 1 did not occur for a prolonged period of time. Customer load on T-2, T-5 and T-11 transmission lines was shed automatically and combustion turbine generation was automatically started.

i. March 7, 2011.
ii. 4.5 hours.
iii. 180 MW.
iv. Internal fault in circuit switcher CS-2 on Reactor 2. No preceding steps were taken by Maritime Electric or NB Power as not weather related and no prior warning.
v. Cable 1 tripped.
vi. The estimated loss of load was about 75 MW including approximate 20 MW of interruptible customer load.
vii. 40 MW of CTs available in Borden; 50 MW of CTs available in Charlottetown; and 50 MW of Steam Plant available in Charlottetown.
viii. Description provided above.
ix. Not applicable.

January 9, 2012
Transmission line Y-103 tripped due to a fault. Cable overload scheme was automatically initiated to ensure overloading of Cable 1 did not occur for a prolonged period of time. Customer load on T-2, T-5 and T-11 transmission lines was shed automatically and combustion turbine generation was automatically started.

i. January 9, 2012.
ii. 0.08 hours.
iii. 80 MW, 120 MW of Non-Firm.
iv. Fault on-line Y-103 between Richmond Cove and Bedeque Switching Station. No preceding steps taken by Maritime Electric or NB Power as not weather related and no prior warning.
v. Cable 2 tripped.
vi. The estimated loss of load was approximately 80 MW including approximately 23 MW interruptible load.
vii. 40 MW of CTs available in Borden; 50 MW of CTs available in Charlottetown; and 50 MW of Steam Plant available in Charlottetown.
viii. Description provided above.
ix. Not applicable.

June 28 to July 29, 2012
In early 2012, Maritime Electric began monitoring gradual pressure changes in Cable 1 when a low oil pressure alarm was received at Maritime Electric's Energy Control Centre ("ECC"). Initial investigation determined it likely that there was a leak somewhere in the Cable 1 oil system.

By March 15, 2012, the evidence was found to be conclusive, and the leak was reported to regulatory bodies. In May, Utilise Limited from the United Kingdom was engaged to inject a special tracer gas (Perfluorocarbon) into Cable 1 oil system. It was eventually determined that there were two oil leaks in the cable. The cable was taken out-of-service on June 28 and was returned to service on July 29 after both leaks had been repaired with splice kits.

i. June 28 to July 29, 2012.
ii. 31 days.
iii. 176 MW.
iv. A slow leak was found in Cable 1. The Company had to wait for the ice-covered Northumberland Strait to clear, and for required marine equipment to become available, and to be modified to suit the cable repair operation. Maritime Electric operated its 60 MW thermal generation in Charlottetown and its fleet of combustion turbines throughout the event to maintain customer load while the import level was limited to 100 MW. On-Island wind generation also helped supply load during the outage. Maritime Electric completed all system maintenance before the planned outage to Cable 1 and Maritime Electric generation staff were supported by other departments to allow the significant increase in workload for the generation department.
v. Cable 1 was out of service, so the maximum import was limited to 100 MW. The outage lasted for 31 days.
vi. There was no loss of load directly attributed to the outage of Cable 1.
vii. All supply and demand resources remained intact throughout the event (40 MW of CTs available in Borden; 50 MW of CTs available in Charlottetown; and 50 MW of Steam Plant available in Charlottetown).
viii. Description provided above.
ix. Not applicable.

Past Prolonged Partial Disconnection (prior to 2004)

<u>December 2 to 27, 1997</u>
On December 2, 1997, Cable 1 tripped when the bulk potato carrier MV Irene dropped and dragged its anchor in a ‘No Anchor Zone’ about 6 km from the PEI shoreline and severed one of the two 100 MW cables in service at the time. A repair crew was mobilized immediately and completed the repairs and lowered the repaired cable to the sea bottom on December 27, 1997, just one day before heavy ice arrived in the Northumberland Strait. The peak winter load was approximately 169 MW in December 1997.[1]

i. December 2 to 27, 1997.
ii. 25 days.
iii. 100 MW.
iv. A ship dropped anchor in a ‘No Anchor Zone’ and severed one of the two 100 MW cables in service at the time. Maritime Electric had 60 MW of Steam Plant in operation at the time of the event due to an impending winter storm. The proactive operation of the 60 MW Steam Plant was the only reason the Island did not experience a loss of load event at that time.
v. Cable 1 was out of service for a total of 25 days, limiting the NB import to 100 MW for that duration.
vi. No loss of load due to system loading at that time.
vii. The 60 MW Steam Plant was operational at the time of the event and remained online

[1] From Prince Edward Island 1997 Annual Statistical Review

until the cable was put back in-service. There was no renewable generation on PEI at that time (40 MW of CTs available in Borden and 60 MW of Steam Plant available in Charlottetown).

viii. Description provided above.

ix. Not applicable.

Partial Disconnections (since filing of 2022 Capacity Resource Study)

December 21, 2022

Cable 3 and transmission line L1143 in NB tripped due to a phase-to-ground fault at 5:59 p.m. while the Interconnection load was approximately 228 MW. This was a low impedance fault potentially caused by a flashed insulator or the phase contacting the ground. There was no adverse weather in the area at the time of the fault.

February 17, 2023

Bus trip forced Cable 3 and Cable 4 to trip.

June 1, 2023

Cable 1 and Cable 2 tripped for vegetation control efforts by ECC at 4:39 p.m. on June 1, 2023, while the Interconnection load was approximately 190 MW. Cables 1 and 2 were back in service at 3:32 p.m. and 3:34 p.m., respectively, on June 2, after the vegetation control tasks finished while the interconnection load was about 80 MW.

June 30, 2023

Cable 3 tripped due to a phase-to-ground fault at 5:59 p.m. while the Interconnection load was approximately 158 MW. There was an adverse weather call in the area at the time of the fault, which could be lightning on transmission line L1143 in NB.

September 5, 2023

Cable 3 tripped due to a phase-to-ground fault at 9:21 a.m. while the Interconnection load was about 145 MW. This was a low impedance fault potentially caused by a flashed insulator. There was no adverse weather in the area at the time of the fault.

September 11, 2023

Cable 3 tripped due to a phase-to-ground fault at 9:37 a.m. while the Interconnection load was approximately 173 MW. The fault was located outside the Cape Tormentine switching station. This was a low impedance fault potentially caused by a flashed insulator. There was light rain at the time of the event.

February 8, 2024

Cable 1 and Cable 2 tripped due to a phase-to-ground fault on Line 1142 at 11:35 a.m. on February 8, 2024, while the Interconnection load was approximately 215 MW. Maritime Electric was able to put Cable 1 back in service at 1:31 p.m.; however, it tripped again at 1:33 p.m. due to the same phase-to-ground fault while the Interconnection load was approximately 203 MW. Cable 3 tripped due to a phase-to-ground fault on Line 1143 at 2:49 p.m. while the Interconnection load was approximately 200 MW. All generation on PEI was started, including Summerside generation. Maritime Electric was holding the remaining Cable 4 to 180 MW to avoid overloading the cable.

Ground patrols by NB Power had been completed around the estimated fault locations on L1142 and L1143 and the crews did not find anything that could have caused these outages. Fault information on L1142 showed a low impedance phase-to-ground fault between Memramcook and Murray Corner. Fault information on L1143 showed a low impedance phase-to-ground fault between Memramcook and Cape Tormentine.

February 9, 2024

Cable 3 tripped due to a phase-to-ground fault on L1143 at 1:33 p.m. on February 9, 2024, while the Interconnection load was approximately 215 MW. Cables 1 and 2 tripped due to a phase-to-ground fault on L1142 at 2:24 p.m. while the Interconnection load was approximately 212 MW. All generation on PEI was started, including Summerside generation. Maritime Electric was holding the remaining Cable 4 to 180 MW to avoid overloading the cable.

Air patrols by NB Power had been completed. The crews did not find anything that could have caused these outages even though they spent a lot of time around “Structure 196” where the fault had been located (near Hardy Road).

Cause for outages on February 8 and 9, 2024 was tracked down to ice on damaged conductor on a bypass structure that was used during the re-configuration of line L1143 in 2017 to re-route the line from Murray Corner to Cape Tormentine, NB. Bypass structure was cut clear and problem was resolved.

APPENDIX B

Review and Report on the November 29, 2018 Storm and Restoration

All our energy.
All the time.

MARITIME ELECTRIC
A FORTIS COMPANY

January 21, 2019

RECEIVED
JAN 2 1 2019
The Island Regulatory and Appeals Commission

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

Dear Ms. Mosher:

Review and Report on the November 29, 2018 Storm and Restoration

Please find enclosed 6 copies of Maritime Electric's Review and Report on the November 29, 2018 Storm and Restoration.

If you have any questions, please do not hesitate to contact the undersigned at 902-629-3696.

Yours truly,

MARITIME ELECTRIC

Jason C. Roberts
Vice President, Finance and
Chief Financial Officer

JCR10
Enclosure

November 29, 2018 Storm Post-Mortem

January 21, 2019

EXECUTIVE OVERVIEW

On the night of November 28, 2018, a winter storm began that affected Maritime Electric Company, Limited (the 'Company') customer supply until December 3. The storm lasted approximately 24 hours and consisted of snow mixed with rain and high winds with peak gusts over 100km/h. Early on November 29, both 138kV transmission lines connecting Western PEI to Central and Eastern PEI tripped off, resulting in the loss of all energy supply to both Central and Eastern PEI. This was shortly followed by the loss of all energy supply from New Brunswick to PEI.

The Company initially encountered issues when attempting to start Combustion Turbine #3 (CT3). When started however, it supplied roughly 30 MW of Charlottetown area load for most of the day. Combustion Turbine #2 (CT2) was also started later on November 29 and supplied a portion of the Borden area load for several hours.

The NB transmission system was ready for energization mid-day, but a number of protection and control issues delayed the energization until later on November 29. Cables #3 and #4 were energized first, but due to ongoing protection and control issues at Murray Corner, Cables #1 and #2 could not be restored until early November 30.

The outages with the most significant impact to customers were generally addressed on November 29, but there remained significant damage to the distribution system. In addition to MECL crews, restoration resources, including 23 contractor crews and 12 mutual aid crews, were dispatched to help with efforts. As western PEI sustained the most damage, the additional resources were sent there first. Central and Eastern Maritime Electric crews completed their restoration efforts before joining the Western district for additional support.

This storm caused an island-wide outage for all 80,000 customers as well as longer outage times for customers in areas with more damage. It also produced the most social media interaction of any event experienced by the Company. SAIDI figures show that the average outage for customers as a result of this storm was 15.85 hours. The estimated cost of restoration was approximately $1,144,500.

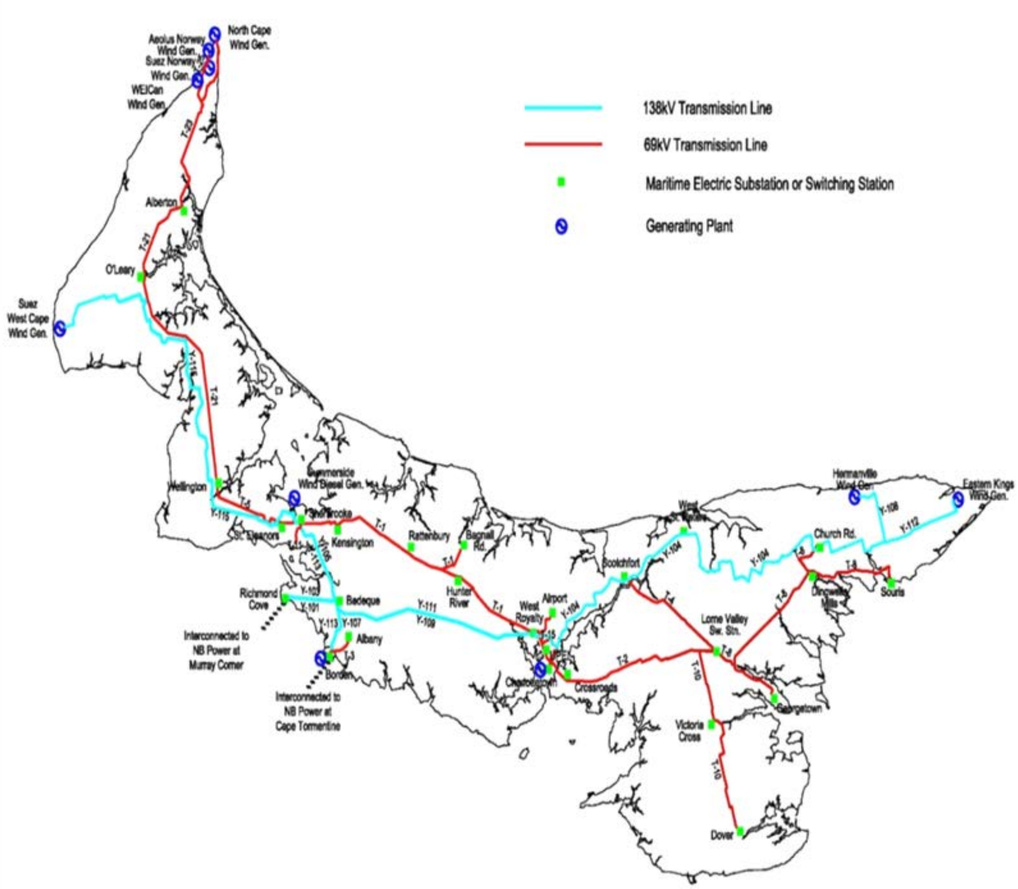
WEATHER

Several days prior to November 28, a forecast of impending inclement weather was issued and the Company began preparations for a potential event. The Company advised Contact Centre personnel and Operations crews of a potential storm response.

Rain, mixed with snow, started to fall on November 28 in the Charlottetown area and continued to sporadically fall throughout the day on November 29. The heavy, wet snow combined with sustained winds of 45-50km/h and peak wind gusts of 100km/h led to downed trees, broken branches and cracked or broken poles, causing outages throughout the electrical system. The temperature remained near the freezing mark through the night on November 28 and all the next day, compounding the impact of the initial damages.

SYSTEM EVENTS LEAD TO BLACKOUT – NOVEMBER 29

The map below shows the Company's on-Island transmission system.



The following is a brief summary of the events that led to the outages experienced due to this storm. For a more detailed sequence of events, please refer to the Summarized Sequential Event Log attached as Appendix ‘A’.

The first outages occurred during the early morning on November 29. Transmission system issues started appearing by 0630 hours, and the Island’s electrical system lost its supply from New Brunswick just before 0900 hours. Two main transmission lines (Y-109 and Y-111) connecting Central and Eastern PEI to Western PEI tripped at 0626 hours and 0728 hours because of tree contacts. This caused a loss of all energy supply to Central and Eastern PEI. At 0821 hours the first of four transmission lines supplying NB Power’s Memramcook substation, the source of supply for all four Submarine Cables between NB and PEI, tripped due to a phase-to-phase fault. The second of four transmission lines into Memramcook substation tripped on a phase-to-ground fault that resulted from snow and ice built-up on conductors and overhead ground wire at 0846 hours. This left one remaining dedicated transmission line feeding the Memramcook substation and a secondary transmission line.

NB Power automatically initiated a remedial action scheme (‘RAS’) to protect the remaining transmission lines. As part of the RAS, NB Power requested that Nova Scotia and PEI dispatch generation in order to alleviate loading on the remaining transmission lines. Before PEI was able to dispatch generation, the final transmission lines feeding Memramcook substation tripped off on thermal protection, cutting all energy supply from New Brunswick to PEI.

SYSTEM AND INTERCONNECTION RESTORATION

At 0755 hours, the Company’s Energy Control Centre (‘ECC’) initiated the black start procedures for Combustion Turbine #3 (‘CT3’) to start generation and reconnect Central and Eastern PEI customers shortly after the loss of the transmission tie between Central/Eastern PEI and Western PEI (Y-109 and Y-111). Initially, the start-up proceeded normally, but an issue with the associated switchgear and the subsequent loss of energy supply from NB Power delayed its operation until mid-morning. At 1000 hours, CT3 started, and ECC began to pick up load in the Charlottetown area beginning with priority areas including the Queen Elizabeth Hospital. The voltage on CT3 was low and could not be increased. This limited the amount of output from the generator, thus limiting the load that could be picked up. At 1615 hours, CT3 tripped off due to low voltage and a mechanical issue forced it into a four-hour cool down lockout before being restarted. In mid-December, the voltage protection for CT3 was modified to enable full output of the unit when in 'Islanded mode' as experienced during the storm.

At 1426 hours, Combustion Turbine #2 ('CT2') located at the Borden Generating Station was started via the black start procedure and was connected to the system. Shortly following this, the Albany station was energized. ECC then began closing the four circuits out of the Albany Substation and found one of the circuits could not be energized. ECC then attempted to synchronize CT2 and CT3 operations by reenergizing the 138 kV system. ECC soon decided to forgo further 138 kV energization as the system protection configuration would not allow synchronizing with Y-107 (Y-107 is a transmission line connecting the Borden Riser Station and the Bedeque Switching Station) out of service. Y-107 had to be de-energized to provide a safe work environment for the Y-109 redirection project, which was ongoing when this storm arrived.

Following NB Power informing the Company that the Memramcook substation was available to supply the Island, the Company's engineering personnel began working with NB Power Technicians to enable the interconnection to be safely reenergized. At 1612 hours, Cable #3 and the associated NB transmission line were energized and at 1620 hours, Cable #4 was energized. With two Cables back on line, the Company was able to focus on energizing transmission lines and substations that were prepared for energization. The work on removing fault conditions on the lines continued through the evening of November 29 and into November 30.

Loss of supply to the Memramcook substation had initiated protection/control issues with the Murray Corner substation that had to be corrected prior to energizing Cables #1 and #2. On November 30 at 0300 hours, Cable #1 was energized and Cable #2 was energized later that morning. Once all four cables were energized, the energy supply from New Brunswick to PEI was secured. CT3 was kept online until mid-afternoon to ensure that the transmission system was reliable, at which point it was taken offline.

CORE TRANSMISSION SYSTEM RESTORATION

Overall, the core transmission and protection system performed relatively well. Outages occurred, mainly due to tree contacts and broken poles on T-2, T-23, Y-101, Y-103, Y-104, Y-109 and Y-111; however, there was no major damage to the transmission system. The Company's transmission system was fully operational just after mid-day on November 30, once the four submarine cables and transmission lines Y-109 and Y-111 were re-energized.

Several substations also sustained restricted operations due to a lack of power. The length of outage to the substations caused their battery banks to drain, which affected remote breaker, and other system control device, operation when trying to reenergize the substations. The Company will be expanding its use of backup generators in substations as a possible solution to this issue.

DISTRIBUTION SYSTEM RESTORATION

The Company responded to distribution outages on November 29 with all of its resources. However, the number of outages was significant, and it was apparent restoration would take some time. At this point the Outage System Level was raised from low (restoration in less than 24 hours) to Medium (restoration in 24 to 72 hours). A more thorough investigation of the distribution system revealed significant system damage, especially in western PEI. The outage system level was elevated again on December 1 from Medium to High (restoration in greater than 3 days).

There were 149 poles damaged during the storm. Of this, five were transmission structures and the remaining 144 were distribution poles. 95 of the 144 distribution poles that were damaged were Eastern Cedar poles, while the remaining were Penta and CCA. There were also 8 transformers and 2.5 km of conductor replaced as a result of the storm.

WIND FARM RESTORATION

A total loss of supply to Central and Eastern PEI occurred when both transmission lines (Y-109 and Y-111) between these areas tripped on November 29. The wind farms in Eastern PEI both tripped at that time due to a lack of system voltage support. The wind farms located in Western PEI tripped when the supply from NB Power was lost.

Company crews completed required repairs during the day and evening of November 30 and all windfarms were back on line by late evening November 30th.

IMPACT ON RELIABILITY

The system average interruption duration index ('SAIDI') is commonly used as a reliability indicator by electric utilities. The SAIDI statistics are indicated in the table below.

Statistic	Hours	Comment
SAIDI (Excluding MED)	0.50	The average SAIDI (excluding Major Event Days) or "expected" average outage without major storm
SAIDI (All-in) – Nov 29 - Dec 3 - Storm	15.85	The average outage experienced by customers as a result of the storm
SAIDI (All-in) - January 2008 Ice Storm	15.56	The SAIDI figure for the last major outage event – An ice storm in January of 2008

OPERATIONS CREWS DISPATCH

Operations crews were dispatched based on the locations for highest-impact of system restoration. In general, Operations crews were initially dispatched to locate the transmission system faults, since the transmission system supplies the largest number of customers. Crews were also dispatched to Bedeque, Borden, and Cape Tormentine to assist in re-establishing the NB-PEI interconnections. While operations crews concentrated on transmission system issues on November 29, they also repaired several distribution system issues that day. After the transmission damages were repaired, there was a concerted focus on repairing the distribution system.

MUTUAL AID AND CONTRACTOR RESOURCES

The Company recognized the significant impact of this storm very early and contacted on-Island contractor crews immediately. On November 29, 16 contractor crews were assisting with the restoration efforts. This number increased to 23 by December 1 (14 H-Line, 4 Atlantic Reach and 5 GSD crews). The Company also reached out to mutual aid partners and Fortis companies on November 29 to investigate the possibility of assistance in the storm clean up. Based on the reports back from the spotters on November 30, the Company decided mid-day on November 30 to utilize mutual aid from outside. A total of 12 crews were brought onto the Island; 4 crews and a supervisor from NB Power, 4 crews and a supervisor from NS Power, and 4 crews and a supervisor from Fortis Ontario.

These crews arrived over the period of December 1-2 and were given a safety and system orientation immediately, then promptly put to work alongside Company personnel.

CUSTOMER RESTORATION

The following table highlights the number of customers out at the indicated time. All customers were restored by 2000 hours on December 3.

Date	Time	# Customers Out
November 29	0900h	80,000
	2000h	34,000
November 30	0600h	35,000[1]
	1600h	7,200
December 1	1600h	2,200
December 2	1800h	1,400
December 3	0700h	750

CUSTOMER SERVICE RESPONSE

This storm produced the most social media interaction of any storm or other event experienced by the Company. Company personnel received phone calls and monitored its various social media platforms – Twitter and Facebook – as well as all other media outlets on a 24/7 basis from early on November 29 through to the final customer reconnection on December 3. In total, the Company had 62,000 website hits, 25,000 phone calls, and over 100,000 social media hits.

SAFETY ISSUES

Five safety issues were identified during the storm restoration. Four related to communication between ECC and field staff carrying out work in substations and during patrols. Investigations and reports have been generated for these incidents. The fifth incident was snow falling off the roof of the Sherbrooke Service Centre, hitting an employee. No injuries were sustained.

[1] Figure is slightly higher than previous evening due to switching operations occurring at that time of the morning. Actual number of customers without power at this time was lower.

ESTIMATED TOTAL COSTS

The impacts on the Company's system were significant. A total of 149 poles were replaced along with over 2.5 km of conductor and eight transformers. The largest financial impact was the cost of labour, both internal and external. As in all similar events, crews worked 16-hour days from November 29 until the last customer was reconnected on December 3. The table below summarizes the costs:

Item	Total Cost
MECL Line Crews and Spotters - Labour & Vehicle	$ 282,000
Contractors - Labour & Vehicle	$ 388,500
Mutual Aid - NS Power	$ 90,500
Mutual Aid - NB Power	$ 80,000
Mutual Aid - Fortis Ontario	$ 119,500
Labour – Storm Super's/Customer Service Reps	$ 16,000
Food and Lodging	$ 44,500
Material (poles, wire, transformers)	$ 103,500
Flagging	$ 20,000
Storm Costs Subtotal	**$ 1,144,500**
Retirement Adjustment (15% of Labour Costs)	$ 149,475
Storm Costs Total	**$ 995,025**
Operational Cost	$ 133,729
Capital Cost	$ 861,296

Appendix ‘A’

Summarized Sequential Event Log

Summarized Sequential Event Log

Below is a high-level sequence of events from the commencement of the storm, through the restoration efforts, ending when all four submarine cables were re-energized:

- 0050h – The first outages of the storm occurred on the distribution system in Charlottetown. Additional outages occurred throughout the early morning hours, primarily in eastern and central PEI.
- 0220h – The Contact Centre was opened.
- 0600h – The first outage in western PEI occurred in Tignish.
- 0626h – One of two 138 kV transmission lines connecting central and eastern PEI to western PEI (Y-111) tripped as a result of a tree contact.
- 0728h – The 2nd 138 kV transmission line between central/eastern PEI and western PEI (Line Y-109) also tripped as a result of a tree contract. The loss of both transmission lines Y-111 and Y-109 caused the loss of all supply to central and eastern PEI. Crews were dispatched from the West Royalty Service Centre ('WRSC') to locate the line faults.
- 0755h – Following the loss of Y-111 and then Y-109 the Company's Combustion Turbine #3 ('CT3') located at the Charlottetown plant site was started via the Company's blackstart procedures. CT3's start-up proceeded normally.
- 0804h – CT3 breaker closed, connecting CT3 to the system. Within seconds, the unit tripped off due to an issue with the associated switchgear.
- 0821h – The first of four transmission lines supplying NB Power's Memramcook substation tripped due to a phase-to-phase fault. The Memramcook substation is the source of supply for all four submarine cables between NB and PEI.
- 0846h – The 2nd of four transmission lines into Memramcook substation tripped on a phase-to-ground fault that resulted from snow and ice built-up on conductors and overhead ground wire. This left one remaining dedicated transmission line feeding the Memramcook substation and a secondary transmission line. A remedial action scheme ('RAS') was automatically initiated to protect the remaining transmission lines. As part of the RAS, NB Power requested that Nova Scotia and PEI dispatch generation in order to alleviate loading on the remaining transmission lines.
- 0854h – CT3 was started a second time. However, during its start up sequence the supply was lost from New Brunswick, causing a system wide blackout and causing CT3 to trip off.
- 0858h – Prior to the PEI and Nova Scotia generation coming online, the final transmission lines feeding Memramcook substation tripped off on thermal protection, cutting all supply from New Brunswick to PEI and Nova Scotia.

- 1000h – CT3 started a third time, and this time the start-up sequence was successful.
- 1030h – ECC used CT3 to slowly pick up load on downtown Charlottetown circuits starting with King Street (which feeds the Charlottetown Thermal Generating Station ('CTGS')). CTGS staff began the process of bringing Heating Boiler #2 back online, which is the first step in bringing the plant back online. All remaining circuits supplied from the Charlottetown substation were brought online by 1105h.
- 1120h – Transmission line T-15, connecting the Charlottetown Substation (and CT3) to West Royalty, was energized, followed by the energization of the West Royalty substation.
- 1134h – The first distribution circuit from West Royalty was energized (Queens Arms), followed by Inkerman and University circuits. Several city circuits had broken poles and could not be reconnected until repairs were completed. In addition, the CT3 output voltage was low and could not be increased, limiting the amount of output from the machine to existing levels.
- 1346h – NB Power informed the Company that the Memramcook substation was available to supply the Island. The Company's engineering personnel began working with NB Power Technicians to enable reenergization of the interconnection.
- 1426h – Combustion Turbine #2 ('CT2') located at the Borden Generating Station was started via the Company's blackstart procedure and was connected to the system, and the Albany station was energized shortly thereafter. ECC then began closing the four circuits out of the Albany Substation, and found one of the circuits could not be energized. ECC then attempted to synchronize (connect) CT2 and CT3 operations by reenergizing the 138 kV system. Issues were encountered and ECC decided to forgo further 138 kV energization until the supply was restored from New Brunswick.
- 1600h – NB Power began testing the transmission lines between Memramcook substation and the new submarine cables #3 & #4. Testing confirmed that the lines were operational.
- 1612h – The NB transmission line and Cable #3 were energized. This was followed by energizing the transmission between Borden and Sherbrooke substations and subsequently the Sherbrooke substation.
- 1613h – Transmission line, T-5, feeding West out of Sherbrooke was energized. St. Eleanor's and Wellington substations were energized.
- 1615h –CT3 tripped offline (low voltage trip), cutting supply to all customers in Charlottetown. Upon a trip CT3 should automatically begin a cool down cycle. However, another issue with the Dorman Diesel blackstart generator did not allow this to happen. This issue was investigated immediately but the delay restricted CT3 from starting its cool down cycle, forcing it into a 4-hour cool down lockout. This restricted CT3 from restarting until after 2040h.
- 1620h – Cable #4 was energized and connected to the Borden Riser Station.
- 1625h – O'Leary and Alberton substations were energized and ECC started to reconstitute distribution circuits in western PEI.
- 1638h – ECC energized the Bedeque substation.

- 1646h – One of the two main transmission lines between western PEI and central/eastern PEI, Y-109, was closed connecting the West Royalty Substation to the NB interconnection. Attempts to close the 2nd transmission line (Y-111) were unsuccessful.
- 1648h – ECC began to reenergize load in the Charlottetown area.
- 1707h – Attempts to close Cable #2 at Murray Corner were unsuccessful.
- 1800h – ECC energized the Crossroads substation. Load restoration continued on loads supplied from West Royalty and Crossroads substations, as well as substations in central PEI.
- 1828h – ECC energized the transmission line T-11, which supplies the City of Summerside.
- 2050h – Cable #3 and the associated NB transmission line tripped due to a fault on the transmission line. Only one line and cable (Cable #4) remained between New Brunswick and PEI. Extreme low voltages caused ECC to cut load in order to maintain system stability.
- 2150h – CT2 was stopped by ECC. Albany substation was then fed from the system.
- 2219h – CT3 was brought online (following the completion of its 4-hour cool down lockout) and began ramping up output. This allowed additional eastern PEI load to be connected due to eastern PEI voltage support. Additional load supplied from West Royalty was also connected.
- 2220h – Attempts to close Cable #2 continued to be unsuccessful.
- 2256h – ECC energized the transmission line T-10 to Victoria Cross and Dover substations.
- 2317h – ECC energized the transmission line Y-104 to Scotchfort, West St. Peters and Church Road Substations.
- 0257h (November 30) – ECC was able to energize Cable #2.
- 1017h (November 30) – ECC was able to energize Cable #1.
- 1333h (November 30) – Cable #3 returned to service after NB Power crews worked to remove the fault condition on line L1143.