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A FORTIS COMPANY

November 12, 2025

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The Island Regulatory and Appeals Commission

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 Second Set of Interrogatories from Synapse Energy Economics
On behalf of Island Regulatory and Appeals Commission

Please find attached Maritime Electric Company, Limited's ("Maritime Electric" or the "Company") responses to the second set of interrogatories from Synapse Energy Economics ("Synapse") on behalf of the Island Regulatory and Appeals Commission (the "Commission") with respect to the On-Island Capacity for Security of Supply Project received on October 29, 2025.

An electronic copy of this submission will be forwarded shortly.

A number of the interrogatories from Synapse are directly or indirectly related to the use of a Battery Energy Storage System ("BESS"). This letter intends to provide the Commission with additional information about the possible use cases of BESSs by Maritime Electric for consideration in its decision.

There are three primary use cases of BESSs in the electric utility industry: (1) energy arbitrage, (2) ancillary services and (3) capacity resource.[1] The three BESS use cases can provide value for a utility and its customers depending on a power system's specific needs and circumstances. These use cases and their implications for Maritime Electric are described in detail in this letter.

In Maritime Electric's case, the value of energy arbitrage is negligible, ancillary service benefits are limited, and the use of a BESS as a capacity resource does not eliminate the need for additional dispatchable generation. Maritime Electric's proposed Accelerated On-Island Capacity Development Solution ("Accelerated Capacity Solution") for 100 MW of combustion turbines ("CT"), as filed in the August 2025 Supplemental Filing ("Supplemental Filing"), is essential to address the Company's capacity deficit and to maintain security of supply for customers at the lowest reasonable cost.

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1 Only one of the use cases can be utilized at any given time. For example, a utility may use a BESS as a capacity resource during the winter months and for ancillary services for non-winter months.

Use Case 1: Energy Arbitrage

Utilizing a BESS for energy arbitrage refers to the practice of charging it when marginal energy costs are low (e.g., during off-peak periods) and discharging it when marginal energy costs are high (e.g., during on-peak periods).[2] Energy arbitrage allows the user to store produced or purchased energy when costs are low and to use it at a later time when energy costs are higher. Economic value is derived when the price spread between low- and high-cost energy is significant enough to compensate for the BESS's round-trip efficiency (typically 85 per cent).[3] Energy arbitrage is more common in jurisdictions with significant variability in energy prices throughout the day due to variability in demand (e.g., nighttime versus daytime load) or supply (e.g., excess solar energy during the day).

Maritime Electric's energy supply situation is unique and currently not suited for energy arbitrage. The Company does not operate baseload generation and, today, 100 per cent of wind energy purchased through power purchase agreements is used instantaneously by customers without the need for curtailments or off-Island exports. As a result, the Company's marginal energy source (i.e., the source of the next unit of energy) is primarily energy purchased from New Brunswick Power ("NB Power").[4,5] Maritime Electric's current Energy Purchase Agreement ("EPA") with NB Power includes fixed energy pricing (i.e., the price is the same for all hours of the year);[6] therefore, Maritime Electric currently has no "low" and "high" marginal energy cost periods that are required for energy arbitrage (i.e., the marginal energy unit price is always the same).

Although Maritime Electric's current EPA with NB Power includes fixed energy pricing, it is evident that NB Power's marginal energy costs are variable. NB Power is currently interconnected with ISO New England ("ISO-NE") which publishes hourly locational marginal pricing ("LMP") for various interconnections including the NB External Node.[7] This ISO-NE LMP represents NB Power's opportunity costs (if they sold electricity to ISO-NE instead of Maritime Electric) and is a reasonable proxy of NB Power's hourly marginal electricity prices for evaluation purposes.

An evaluation of hourly ISO-NE LMP for the NB External Node in 2024 reveals that the average off-peak electricity price was \$46.41/MWh and the average on-peak price was \$57.41/MWh.[8] This information is useful in evaluating the potential economic value of energy arbitrage in the region. A 50 MW 4-hour BESS has a total energy storage capacity of 200 MWh. A round-trip efficiency of 85 per cent results in 216 MWh required to fully charge the BESS and 185 MWh available for discharge.[9] Charging the BESS with 216 MWh during off-peak periods at \$46.41/MWh has a cost of \$10,025. Discharging the energy stored provides 185 MWh to the grid during on-peak periods when energy prices are \$57.41/MWh, resulting in \$10,621 of avoided costs. Using the BESS for energy arbitrage, in this scenario, would provide a value of approximately \$596 per cycle (on

2 Marginal energy costs refer to the price to produce the next unit of electricity demand and is analogous to avoided energy costs.

3 Round-trip efficiency is the ratio of the BESS's total useful energy discharged relative to the total energy required to charge it. A round-trip efficiency of 85 per cent indicates total losses of 15 per cent.

4 Maritime Electric purchases energy and capacity from New Brunswick Energy Marketing Corporation, but "NB Power" is used for simplicity.

5 The only exception is during periods when energy from NB Power is curtailed and Maritime Electric's CTs are operating.

6 The current EPA with NB Power expires at the end of 2026.

7 Location ID number for the NB External Node is 4010; location name is ".ISALBRYNB345 1."

8 Converted to CAD using a USD to CAD exchange rate of 1.37 in 2024. Based on ISO-NE published on- and off-peak periods.

9 200 MWh / 92.5% = 216 MWh. 200 MWh x 92.5% = 185 MWh.

average) or $152,650 for the 2024 year (assuming one full charge/discharge cycle per day).[10] This annual value is negligible relative to the capital cost of installing a 50 MW 4-hour BESS, which is estimated at $135.5 million.[11]

Maritime Electric's energy supply circumstances and negligible potential economic value of energy arbitrage in the region do not currently support using a BESS for energy arbitrage.

Use Case 2: Ancillary Services

Utilizing a BESS for ancillary services refers to the practice of using it to support grid reliability and stability by providing services such as frequency regulation, voltage support, spinning reserve and load following. These ancillary services are described in detail in Section 6.1 of the December 2024 Application.

Maritime Electric's current ancillary services obligations that could be supported by a BESS include 4.7 MW of load following and 7.8 MW of spinning reserve (12.5 MW total).[12] Maritime Electric's December 2024 Application proposed using the 10 MW 4-hour BESS to meet 10 MW of its ancillary service requirements during periods of the year that the BESS is not required as a capacity resource (see use case 3). This use of the BESS improves the business case for it; however, a BESS larger than 12.5 MW has diminishing value because 12.5 MW is the upper limit of the BESS's use to meet the Company's ancillary service obligations.

Maritime Electric's December 2024 Application, which proposed a 10 MW 4-hour BESS, takes advantage of the BESS's full 10 MW capacity to meet the Company's ancillary service obligations. BESSs that are larger than 12.5 MW provide no incremental ancillary service benefit.

Use Case 3: Capacity Resource

Utilizing a BESS as a capacity resource refers to the practice of deploying it to supply power during peak periods. Maritime Electric's December 2024 Application proposed using the 10 MW 4-hour BESS as a 10 MW capacity resource during the winter period from December to February to help meet the Company's capacity requirement. Section 8.3 of the December 2024 Application explained why Maritime Electric did not propose additional BESS capacity.

The challenge with using a BESS as a capacity resource is that it is fundamentally different than traditional dispatchable generation resources due to its limited supply duration. As such, electric utilities and system operators must study the use of BESSs as capacity resources to determine their effective load carrying capability ("ELCC"). The ELCC is the portion of the nameplate capacity that can be reliably counted as a capacity resource towards meeting the capacity requirement. BESS ELCC studies are complex because they are dependent on the BESS's ability to discharge stored energy during peak periods and whether there are sufficient surplus generation resources (such as wind, solar, dispatchable generation and off-Island energy) to charge the BESS during off-peak periods.

Figure 1 shows a visual representation of Maritime Electric's energy resources to illustrate that the ability of a BESS to reliably contribute as a capacity resource depends on the foundation

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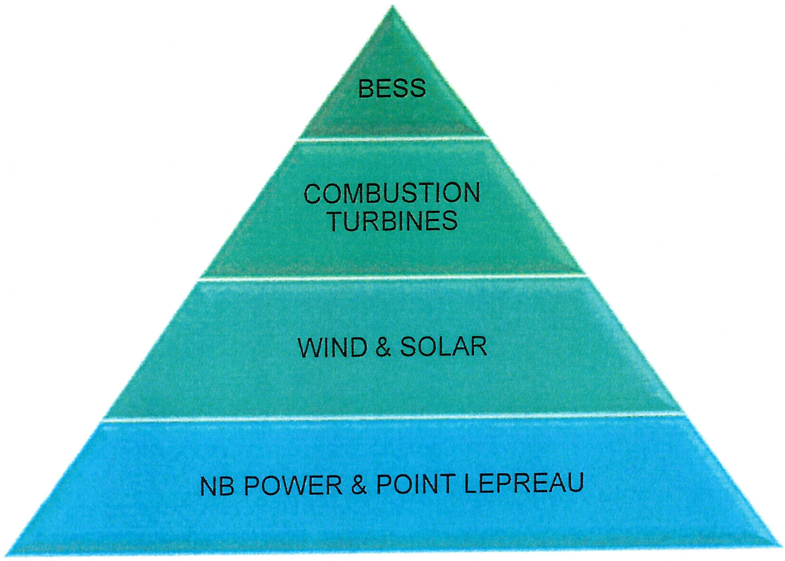
10 $10,621 – 10,025 = $596/cycle. $596/cycle x 256 days with on-peak periods = $152,650/year.

11 Capital cost estimate based on Sargent and Lundy December 2022 cost estimate.

12 Maritime Electric also has a 1.7 MW automatic generation control obligation, but there is currently uncertainty about whether this ancillary service can be supported by a BESS.

provided by other generation resources. Below BESS in the pyramid, in order of dependency, are Maritime Electric's energy resources (including NB Power, Point Lepreau, wind, solar and CTs) that can supply energy needed to charge the BESS before peak demand periods. Maritime Electric is forecasting such a significant capacity resource deficit (156 MW by 2033) that it will not have sufficient generation resources to provide a strong foundation for a BESS. Without a strong foundation, a BESS cannot be charged effectively, and its ability to act as a reliable capacity resource is limited.

FIGURE 1
Pyramid of Maritime Electric's Energy Resources



Some other jurisdictions have begun studying BESS ELCC. Recently, Nova Scotia Power Incorporated ("NSPI") published BESS ELCC values used in its Integrated Resource Plan ("IRP") studies. In August 2023, Synapse provided comments to the Nova Scotia Energy Board ("NSEB," formerly the Nova Scotia Utility and Review Board) regarding NSPI's calculation of BESS ELCC in the 2023 Evergreen IRP.[13] In its comments, Synapse stated the following:

> *As noted, the battery energy storage ELCC profile used in this IRP update is a critical input value to the modeling that needs to be carefully re-examined in the next IRP or IRP update. The re-examination needs to be conducted in conjunction with an updated "portfolio ELCC" analysis that better considers the interactive effect of all four clean resources (wind, solar PV, battery energy storage, and demand response or peak load mitigation during winter peak periods). The current input assumptions used for ELCC for the portfolio of resources, while reflecting some level of diversity benefit, do not fully capture this critically important dynamic.*

In response to the Synapse comments, NSPI acknowledged the recommendation to expand the ELCC study and agreed to investigate it prior to completing the next IRP.[14] However, NSPI stated that:

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13 NSEB Matter M11307 Exhibit N-3 page 6.
14 NSEB Matter M11301 Exhibit N-5 page 7-8.

> *[...]there is an average requirement of approximately 600MW of new fast acting generation capacity by 2032 in No Atlantic Loop Evergreen IRP scenarios. The Company's 2023 Load Forecast Report also shows accelerated firm peak growth relative to the 2022 Load Forecast Report. Accordingly, although there is potential value in the diversity benefit of added solar and storage, further study is not necessary prior to proceeding with the first addition of 300MW of new fast acting generation with an in-service target of 2027 identified in the 2030 Resource Development Plan.*

Due to timeline constraints, the NSEB accepted the results of the 2023 IRP Update, as filed, but directed NSPI to consider Synapse's comments in the next iteration of its IRP.

Maritime Electric acknowledges that more than the 10 MW of BESS capacity proposed in its December 2024 Application may be technically feasible as a reliable capacity resource, but this would require further study to evaluate the ELCC of BESS under various diversified energy portfolios. While the Company is prepared to study the potential for additional BESS capacity beyond what was proposed in the December 2024 Application, such study should not delay proceeding with the first 100 MW of CTs proposed in the Supplemental Filing. The December 2024 Application identified the need for 150 MW of additional capacity and the Company expects to continue to purchase 190 MW of capacity from NB Power. If a larger BESS is deemed technically and financially viable, it can serve to meet the remaining 50 MW of the December 2024 Application or offset capacity purchases from NB Power.

Capacity Cost Comparison

In addition to the technical issues already discussed, using a BESS larger than 10 MW for capacity is not the least cost solution. Table 1 shows a cost comparison of the Accelerated Capacity Solution with high, medium and low BESS ELCC scenarios for a 50 MW 4-hour BESS. The results show that, even if a 50 MW 4-hour BESS has an ELCC of 100 per cent (i.e., the full nameplate capacity can be counted), the present monthly capacity cost of the BESS ($24,366/MW-month) is over three times more expensive (as a capacity resource) than the proposed Accelerated Capacity Solution ($6,863/MW-month).[15]

TABLE 1
Capacity Cost Comparison for BESS ELCC Scenarios

		Accelerated Capacity Solution	**4-Hour BESS High ELCC**	**4-Hour BESS Medium ELCC**	**4-Hour BESS Low ELCC**
Nominal Capacity (MW)	A	100	50	50	50
ELCC (%)	B	100	100	75	50
ELCC (MW)	C = A x B	100	50	37.5	25
Useful Life (years)	D	50	20	20	20
Installed Cost ($ x 1,000)	E	334,229	135,523	135,523	135,523
Present Costs					
Present Cost ($ x 1,000)	F	411,757	158,684	158,684	158,684
Equivalent Annual Cost ($ x 1,000)[a]	G	8,235	14,620	14,620	14,620
Present Monthly Capacity Cost ($/MW-yr)	**H = (G x 1,000) / C**	**82,350**	**292,400**	**389,867**	**584,800**

a. Calculated using Maritime Electric's weighted cost of capital.

15 24,366 / 6,863 = 3.55.

Conclusion

There are three primary use cases for BESSs in the electric utility industry, of which only one can be utilized at a given time. Maritime Electric's energy supply situation does not currently support using a BESS for energy arbitrage. The Company has 12.5 MW of ancillary service obligations that can be supported by a BESS, but BESSs that are larger than 12.5 MW provide no incremental ancillary service benefit. There are opportunities to study the ELCC of BESSs for use as a larger share of capacity resources in Maritime Electric's system and the Company is prepared to do so, but this does not eliminate the critical and immediate need for the 100 MW of CTs proposed in the Supplemental Filing.

Under the provisions of the PEI *Electric Power Act*, Maritime Electric is responsible for providing a reliable and secure supply of electricity to customers and making prudent investments to ensure service is delivered at the lowest reasonable cost. Under current system conditions, a BESS by itself is not a reliable capacity option, nor is it the least cost solution to the very serious capacity deficit facing the Company. For this reason, the proposed Accelerated Capacity Solution, which is critical to maintain security of supply for customers at least cost, must proceed immediately.

Should you require clarification or additional information concerning the content of this letter or the attached interrogatories responses, please let me know.

Yours truly,

MARITIME ELECTRIC

Michelle Francis
Vice-President, Finance & Chief Financial Officer

MF50
Enclosure

RESPONSES TO ADDITIONAL INTERROGATORIES
OF
SYNAPSE ENERGY ECONOMICS

On-Island Capacity Application
(UE20742)

Submitted November 12, 2025

IR-1 Lead Times.

On page 66 of MECL's December 2024 Supplemental Capital Budget Request, MECL states that it expects that specific BESS equipment associated with a 10 MW BESS project would have lead times of approximately one year from the time of order. It also notes that other components are expected to have an 18-month lead time. MECL also notes, in footnote 98, that longer lead times ("…could require up to three years…") may be required depending on the "final arrangement". MECL also includes, in the August 14, 2025 Supplemental Budget Request, at page 15, that "2 x generator step up transformers" appear to be required for the CT project.

a. Please confirm or explain otherwise whether MECL continues to estimate a one-year lead time for BESS equipment for a 10 MW scale BESS facility.
b. What is MECL's current best estimate for the lead time for BESS equipment (e.g., battery and inverter modules) for a 50 MW, 4-hour or 6-hour facility?
c. What is MECL's current best estimate for the lead time for BESS equipment (e.g., battery and inverter modules) for a 100 MW, 4-hour or 6-hour facility?
d. Confirm or explain otherwise that the 2x generator step up transformers listed on page 15 of the Supplemental Request are to be provided by the ProEnergy contractor.
e. Other than the CTs that are part of the proposed project, what are the longest lead-time items associated with the overall project?
f. If MECL considered installation of a 50 MW or 100 MW BESS facility at the Charlottetown site, would new step up transformer(s) be required? If so, what is MECL's estimate of the lead time for such equipment?
g. If MECL's current lead time estimate for BESS equipment differs from the December 2024 estimate, please provide the updated lead time estimate, the date and source of the updated information, and a description of the factors or market developments that led to the change.

Response:

a. Maritime Electric Company, Limited ("Maritime Electric" or the "Company") confirms that its current estimate for the delivery lead time of specific Battery Energy Storage System ("BESS") equipment for a 10 megawatt ("MW") facility remains approximately one year from the time of order. This estimate specifically applies to core BESS components such as battery modules and inverter systems.

However, this timeline does not include the delivery of ancillary equipment required to connect the BESS to the electrical grid. Items such as step-up transformers, breakers, and other interconnection infrastructure may have longer procurement timelines. Based on recent market assessments and vendor discussions, these components may have 2 to 2.5 year lead times, depending on manufacturer availability, global supply chain conditions and final technical specifications.[1]

b. Maritime Electric estimates that the expected delivery lead time for a 50 MW BESS (4-hour or 6-hour) is comparable to the delivery lead time of a 10 MW BESS, as outlined in the response to IR-1(a).

[1] There are some mitigating measures that Maritime Electric could exercise to reduce lead times for some of the long-lead items. More details are provided in the response to IR-1(e).

c. Maritime Electric estimates that the expected delivery lead time for a 100 MW BESS (4-hour or 6-hour) is comparable to the delivery lead time of a 10 MW BESS, as outlined in the response to IR-1(a).

d. Maritime Electric confirms that the two generator step-up transformers referenced on page 15 of the Accelerated On-Island Capacity Development Solution ("Accelerated Capacity Solution"), as filed in the August 2025 Supplemental Filing ("Supplemental Filing") were originally expected to be provided by ProEnergy. This arrangement aligns with the typical structure of ProEnergy's turnkey offerings to prospective clients, where major interconnection components (e.g., step-up transformers) are included in the scope of supply.

Given the urgent need to address the Company's current capacity deficit and the lengthening industry procurement timelines, the Company is evaluating the possibility of directly procuring certain long-lead items. These may include the step-up transformers and associated breakers. This contingency approach is intended to mitigate procurement risks and preserve the coordinated development benefits outlined in the Supplemental Filing.

e. Other than the combustion turbine ("CT") package, components with extended procurement timelines include:

- **Step-up transformers** may require up to two years (or longer) for delivery, depending on manufacturer availability and specification.
- **High-voltage breakers** may require up to 2.5 years for delivery.[2]
- **Switchgear** may require up to 2.5 years for delivery.
- **Reverse osmosis/electrodeionization (RO/EDI) water purification system** may require up to two years for delivery.

Maritime Electric continues to assess procurement strategies to mitigate schedule risks associated with these components.

f. A 50 MW or 100 MW BESS facility, whether installed at the Charlottetown site or another location, would require step-up transformation equipment to integrate BESS output with the transmission system. As noted in the response to IR-1(a), the current expected delivery lead time for step-up transformation equipment is approximately two years.

g. Maritime Electric confirms that the expected delivery lead time for BESS equipment is the same as the December 2024 estimate, as outlined in Response to IR-1(a).

[2] Breaker delivery timelines are based on Maritime Electric's standardized system-wide breaker specification. While this specification is expected to remain unchanged, alternative breaker models are available and may offer shorter lead times, potentially reducing delivery to as little as one year.

IR-2 Use Case for the Proposed Project.

On page 13 of MECL's December 2024 Supplemental Capital Budget Request, MECL states that "This capacity will primarily serve as peaking and backup capacity for responding to unplanned system events, hold-to-schedule directives from NB Power and facilitating planned maintenance activities." MECL also states that the project will reduce the need for off-island capacity purchases, will support additional renewable energy development and enhance the reliability and security of electricity supply to customers. At page 68, MECL lists "Project Justification" elements including "limit exposure to Interconnection transfer limitations or curtailments from the NB system, which is a reliability benefit for customers". In this respect:

a. Confirm or explain otherwise that the above points summarize MECL's "use case" criteria for the proposed project. If additional "use case" elements are part of the proposal, please further explain those elements.
b. Is the "limit exposure…[to] curtailments" in reference to NB firm energy, non-firm energy, or both? Please discuss.
c. Confirm or explain otherwise that NB import energy for MECL's use (firm, or non-firm) can, and is, made available to MECL in part and at different times by NB energy marketing physically delivering less energy from New Brunswick proper, while simultaneously allowing some of its share of on-island (PEI) wind capacity (i.e., West Cape wind farm) to be used to meet a portion of MECL's firm or non-firm energy requested.
d. State the operational conditions under which the CTs are expected to be dispatched (e.g., peak demand periods, system contingencies).
e. What is MECL's expectation for the typical duration of continuous CT dispatch, expressed in units of hours or days (e.g., a period of hours on a peak day, operation for a full day, or for multiple days), when the proposed project CT would be operated? If MECL expects different continuous operation patterns under different contingency conditions, please include this differentiation in your response.
f. Provide any additional details concerning the magnitude, frequency and duration of either a partial or a full NB interconnection outage that MECL is planning for with the proposed project.
g. Confirm, or explain otherwise, that at this time the proposed project, on its own, would not be able to fully support MECL's winter peak load needs under a circumstance where the full interconnection capacity with New Brunswick is severed, and that loss of firm load would be expected in that circumstance.
h. Confirm, or explain otherwise, that required planning considerations would not expect MECL to have sufficient capacity to meet winter peak load day conditions under the severe event of a loss of the full interconnection capacity with NB.

Response:

a. Confirmed.

Although the use cases listed above represent the primary drivers for the proposed project, Maritime Electric has previously referenced several additional operational and reliability considerations throughout its filings and technical submissions. While these additional use cases may not have been the central focus of earlier discussions, they nonetheless reflect evolving system conditions, emerging technical requirements, and strategic planning considerations that have become increasingly relevant in the context of Prince Edward Island's ("PEI") capacity deficit and the broader energy transition.

Additional use cases include:

- **Improved Load-Serving Capability During Disconnection Events**
  The proposed project will strengthen Maritime Electric's ability to maintain service during a complete disconnection from the mainland. As outlined in Section 7.2.3 of the December 2024 Application, the Company currently cannot operate renewable generation under such conditions due to insufficient short-circuit current and system stability. Adding dispatchable on-Island generation could enable partial operation of renewable resources during these events, improving load coverage and reducing the impact of load shedding.
- **Synchronous Condensing Operation for Voltage Support**
  The proposed CTs are capable of synchronous condensing operation, which is critical for maintaining voltage stability during high load periods. The December 2024 Application indicated that, if the project does not proceed, Maritime Electric would need to install a source of dynamic reactive power support in central or eastern PEI.[3] This reinforces the value of the proposed project in avoiding additional capital expenditures while meeting system stability requirements.
- **Transmission Contingency Support During High Load Conditions**
  CTs may be dispatched preemptively during high demand periods (e.g., PEI load exceeding 300 MW) to ensure sufficient contingency response capability in the event of a transmission line outage. This operation helps maintain voltage stability and mitigates the risk of cascading outages.[4]

b. The reference to "curtailments" in the context of the proposed project applies to both firm and non-firm energy imports from New Brunswick Power ("NB Power").

Maritime Electric receives 30 MW of firm energy from the Point Lepreau Nuclear Generating Station ("Point Lepreau") through its 4.5 per cent Unit Participation Agreement and purchases 185 MW of firm capacity from NB Power under its Energy Purchase Agreement ("EPA") (215 MW total firm).[5]

Energy imports above 215 MW are considered non-firm and are only available when surplus energy exists on the NB Power system. These non-firm imports are subject to curtailment at NB Power's discretion, particularly during high demand periods or generation shortfalls.

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[3] Section 7.5 of the December 2024 Application outlines the need for dynamic reactive power support and the ability of a CT to provide this reactive power support through synchronous condensing operation.

[4] The use of on-Island dispatchable generation to protect against transmission system contingencies was previously discussed in the Company's responses to IRs 54, 55 & 56 in the Additional Interrogatories from Commission Staff on the 2025 Capital Budget Application (docket UE20741) dated July 31, 2025. There is also additional information on this use case included the in response to IR-2(d) herein.

[5] Due to 3.3 per cent losses on the transmission system in New Brunswick, the Company receives 29 MW net of losses from Point Lepreau and 179 MW net of losses from NB Power (208 MW total). As per Section 5.1.2 of the December 2024 Application, Maritime Electric has been allotted 185 MW of firm capacity from NB Power for 2025, which increases to 190 MW in 2026. NB Power has indicated that it intends to continue to provide this level of firm capacity to Maritime Electric in the future, but that it does not expect to be able to increase this allotment.

Curtailments that reduce imports from 270 MW to 215 MW impact non-firm energy imports only. Curtailments that reduce imports below 215 MW impact both non-firm and firm imports. Transmission outages, transmission reconfigurations or generator outages can reduce imports to below 215 MW, regardless of contractual entitlements. The proposed project is intended to mitigate these risks by increasing on-Island dispatchable generation, thereby reducing reliance on imports that are increasingly subject to curtailment and uncertainty.

c. Under current arrangements, energy generated by PEI wind resources and sold outside the province (i.e., West Cape wind energy) is contractually delivered to NB Power. Maritime Electric, in turn, receives its full allocation of firm or non-firm energy from NB Power. In practice, however, physical delivery does not always match these contractual flows. Although the contract specifies delivery from NB Power, West Cape wind energy typically remains on PEI and is consumed locally. This reduces the amount of energy that must be physically imported from New Brunswick ("NB") through the submarine cable interconnection.

The interconnection cables between PEI and NB Power can only transfer energy in one direction at a time. When West Cape wind energy is used locally, it offsets the need for simultaneous imports from NB, even though the contractual exchange still reflects delivery from NB Power.

This operational dynamic is a key consideration in Maritime Electric's planning for on-Island capacity and reliability, especially during peak demand and contingency events. However, it does not change the contractual energy exchange between the utilities. NB Power's firm energy allotment is based on contractual flows, not physical flows. For example, if Maritime Electric requests 230 MW of import, exceeding the 215 MW firm allotment, and NB Power has no non-firm energy available, only 215 MW will be supplied. If 50 MW of West Cape wind energy is generated and sold to NB Power, the physical import would drop to 165 MW. Despite this lower physical flow, the contractual limit of 215 MW remains, and NB Power has no obligation to provide the additional 15 MW.

d. As outlined in the December 2024 Application and subsequent filings, the CTs are intended to serve as a flexible capacity resource capable of responding to a range of system conditions. The following response consolidates all dispatch scenarios referenced to date, including both primary use cases and additional operational considerations. This comprehensive list reflects the evolving role of dispatchable generation in supporting system adequacy, reliability and strategic planning objectives.

1. System peak demand periods;
2. Unplanned system events;
3. Voltage support via synchronous condensing;[6]
4. Curtailments from NB Power;
5. Islanded operation (disconnection from mainland);[6]
6. Hold-to-Schedule directives from NB Power;
7. Planned and forced maintenance activities;
8. Transmission contingency support during high load conditions;[6]

[6] Additional use case as described in the response to IR-2(a).

9. Activation of supplemental reserve;[7]
10. Emergency energy supply to third parties; and
11. Monthly test runs.

e. The expected duration of continuous CT dispatch varies depending on the operational conditions under which the CT was dispatched. The expected duration of continuous CT dispatch for each of the 11 operational conditions identified in response to IR-2(d) is provided below.

1. **System Peak Demand Periods -** CTs may be dispatched for several hours during peak load days (typically in the winter months). Typical duration is three to eight hours, depending on load levels and the availability of imports and renewable generation. However, longer dispatch durations are possible during significant events. During the February 2023 polar vortex, Maritime Electric dispatched CTs continuously for more than 48 hours.[8]

2. **Unplanned System Events (e.g., faults, outages) -** CTs may be dispatched for emergency response. Typical duration is one hour up to multiple days, depending on the severity and duration of the event.

3. **Voltage Support via Synchronous Condensing -** When operating in synchronous condenser mode, CTs consume no fuel and can remain online for extended durations (potentially several days) during periods of high system load or voltage support requirements.[9] Based on current transmission system conditions, Maritime Electric anticipates that a synchronous condenser located at the Charlottetown Generating Station would be engaged when PEI loads exceed 300 MW. Beginning in 2029, the earliest expected year of synchronous condenser availability /operation, the Company expects at least one CT to operate in synchronous condensing mode for approximately 700 hours annually, with 2.5 days as the longest continuous operation.

4. **Curtailments from NB Power -** When firm or non-firm imports are curtailed, CTs may be dispatched for several hours up to a full day (or longer). Duration depends on the extent and timing of the curtailment.

5. **Islanded Operation (Disconnection from Mainland) -** In the event of full interconnection loss, CTs may be dispatched continuously for the duration of the event. Duration will depend on the reason for the disconnection and could range from hours to days.

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[7] As outlined in Table 11 of the December 2024 Application, Maritime Electric's CTs are held in reserve to meet the Company's share of its mandatory 10-minute and 30-minute operating reserve requirements, currently 19.7 MW and 16.4 MW respectively. During peak months (i.e., December through February), the CT fleet is used as a capacity resource, while for the remainder of the year, these units are redeployed to fulfill supplemental reserve obligations, offsetting the cost of purchasing reserve products from NB Power for eight months annually.

[8] Refer to Maritime Electric's April 23, 2025 letter to IRAC (Exhibit M-3), which notes that due to increased system loading since 2023, winter peak loads now reach polar vortex levels at expected winter peak temperatures.

[9] Although no fuel is consumed when a CT operates in synchronous condensing mode, The generator draws modest electrical energy from the grid to remain synchronized. This results in minor electrical losses and associated operating costs.

6. **Hold-to-Schedule Directives from NB Power -** CTs may be dispatched for one to three hours to maintain scheduled import levels when NB Power is unable to accommodate real-time adjustments.

7. **Planned and Forced Maintenance Activities -** Typical planned transmission system maintenance activities may require CT dispatch for 4 to 12 hours to support system reliability during scheduled transmission outages. Unplanned or forced maintenance events can last several days and may require CT operation during daily peak periods or continuously for the duration of the outage.

8. **Transmission Contingency Support During High Load Conditions -** Preemptive CT operation may be initiated during periods of elevated system loading to ensure transmission contingency coverage. While typical dispatch duration is expected to cover the peak hours of the day, the amount of time spent above the minimum threshold for preemptive running is increasing as system load increases.

   In the analysis supporting Maritime Electric's Responses to IR-54, IR-55 and IR-56 of Additional Interrogatories for the 2025 Capital Budget Application (Exhibit M-6),[10] Maritime Electric predicted a maximum preemptive run time of 25 hours, with 11 occurrences longer than six hours and 18 occurrences longer than four hours.[11] These findings reflect the growing need for sustained contingency coverage, particularly during high-risk periods when transmission assets operate near thermal and voltage limits.

   As load continues to increase, in the absence of expansion of the transmission system, the duration of preemptive CT dispatch is expected to extend beyond traditional peak periods, reinforcing the importance of on-Island dispatchable generation to maintain system reliability.[12]

9. **Activation of Supplemental Reserves –** When CTs are operated as a supplemental reserve (i.e., 10-minute and 30-minute), they must remain available for immediate dispatch and cannot be used for other purposes. Following a directive from the New Brunswick Transmission System Operator, the reserved CTs must be started and operate for up to 60 minutes.

10. **Emergency Energy Supply to Third Parties -** Dispatch duration varies depending on the nature of the regional shortfall, but could range from a few hours to multiple days.

11. **Monthly Test Runs -** Test runs typically last one hour or less.

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[10] Docket UE20741.

[11] The analysis was completed for January and February 2030.

[12] Maritime Electric does not anticipate designing the transmission system to depend on preemptive CT operation during periods of high system loading. Instead, the system is being planned to withstand contingencies under peak conditions. Where necessary, short-duration preemptive CT operation may be used as a transitional reliability measure until transmission upgrades are completed, reflecting a balanced approach between operational flexibility and prudent investment timing.

f. Maritime Electric has experienced both full and partial disconnection events from NB, and these historical occurrences inform the planning assumptions for the proposed capacity additions.

Since 2004, there have been four full disconnection events and five partial disconnection events that resulted in loss of load. A complete list of full and partial disconnection events between 2004 and 2024 was included in the Company's Response to Interrogatories from Synapse Energy economics on behalf of PEI Regulatory and Appeals Commission IR-8 (Exhibit M-6), filed on May 16, 2025. There have also been several partial disconnections over this same period, which did not result in loss of load but are relevant for reliability planning. Details concerning magnitude, frequency, and duration of partial and full NB interconnection outages follow.

- **Magnitude:** Full disconnection events have resulted in the loss of up to 240 MW of firm load, as seen during a November 29, 2018 storm event. Partial disconnections have typically involved a fault of one or more subsea cables, reducing import capability by 100 to 120 MW, depending on the cable affected;
- **Frequency:** Partial disconnections have occurred multiple times in recent years, including events in December 2022, February 2023, June 2023, September 2023 and February 2024; and
- **Duration:** Outage durations have ranged from less than one hour (e.g., April 28, 2004) to multi-day events (e.g., December 1997 25-day outage of Cable 1 caused by a marine vessel anchor severing a cable).

Maritime Electric's planning for the proposed capacity additions considered all of these historical outage scenarios.

g. Confirmed. Please refer to Section 7.2.3 of the December 2024 Application for detailed information.

h. Confirmed. Please refer to Section 7.2.3 of the December 2024 Application for detailed information.

IR-3 BESS Alternative.

At page 113 of the December 2024 Application, MECL states "A large-scale BESS to address the forecast capacity deficit during a system peak is not recommended as the system peak reduction capabilities of a BESS are limited". MECL provides as an academic exercise Figure 29 (system peak load curve) and Table 21(BESS peak reduction capabilities) as part of the section addressing BESS as an alternative.

a. In examining large-scale BESS as an alternative to the proposed project, to what extent has MECL considered the ability of a BESS alternative to optimize the multi-hour supply of energy available from on-island wind resources and energy available from NB imports, during the full course of a winter peak day (as opposed to its ability to "reduce system peak")?

b. Please discuss which of these two "use cases" for BESS – reduce peak load, vs. optimize energy availability across on-island and off-island resources – best support the overall goals associated with on-island capacity supply.

c. Confirm that a 100 MW BESS resource at the Charlottetown plant site would meet all of the "Project Justification" bullet points listed on page 68 of the December 2024 Application. If not confirmed for any of the seven points, provide an explanation of why MECL does not think such a resource meets the criteria.

d. If MECL sees a distinction between the way in which the proposed project and a similarly-size BESS capacity alternative (at either 4 hours or 6 hours duration) would provide the benefit for any given element listed, please fully describe the nature of the distinction.

Response:

a. The cover letter to these interrogatory responses discounts large-scale BESS as an alternative to the solutions presented in the December 2024 Application and August 2025 Supplemental Filing. However, the Company is prepared to assess the effective load carrying capability ("ELCC") of BESS within diversified energy portfolios to determine whether a technically and financially viable large-scale BESS addition could compliment the first 100 MW of CTs proposed in the Supplemental Filing.

The Company's immediate priority remains addressing the significant capacity deficit identified in the December 2024 Application. The proposed 100 MW of CTs in the Supplemental Filing represents a critical step toward achieving security of supply for customers. Even if future BESS expansion proves feasible, dispatchable generation will continue to play an essential role in meeting system reliability requirements. Accordingly, Maritime Electric does not consider it prudent to delay the current capacity solution pending further study of BESS alternatives.

b. The primary objective of the December 2024 Application and the Supplemental Filing is to address Maritime Electric's capacity resource deficit. As such, the use case of a BESS as a capacity resource best supports that goal.[13] Please refer to the cover letter to these interrogatory responses for details regarding the use of a BESS as a capacity resource (use case 3).

[13] Maritime Electric does not consider the addition of a BESS to be a reduction in peak load. Rather, the BESS is treated as a capacity resource that contributes to meeting the peak load requirement. It does not reduce the peak itself but instead provides energy during peak periods to help satisfy demand.

The alternative use case (i.e., optimizing energy availability across on-Island and off-Island resources), is not included in the Company's proposed capacity solutions because it is already achieved through PEI's interconnection with NB for the vast majority of the year. This interconnection enables Maritime Electric to consume all of the renewable energy generated on PEI, when it is generated, and supplements this renewable generation with imported energy when needed. It is generally only when this combination of on-Island and off-Island resources cannot meet customer load that Maritime Electric must operate its CTs. Between 2019 and 2023 this was achieved 99.8 per cent of the time.[14]

c. Maritime Electric confirms that a 100 MW BESS would generally satisfy all the project justification criteria listed on page 68 of the December 2024 Application, but not to the same extent as the solutions proposed in the December 2024 Application or the Supplemental Filing. Details on the extent to which a BESS would satisfy each of the justification criteria is provided in the response to IR-3(d).

d. A 100 MW BESS would not result in savings compared to purchasing capacity from off-Island resources (criteria #1) to the same extent as the other proposed solutions. Please refer to the conclusion section of the cover letter to these responses for a comparison of the cost of a BESS relative to the Accelerated Capacity Solution.

A 100 MW BESS would reduce exposure to regional capacity shortages (criteria #2) and decrease exposure to capacity market prices (criteria #6), but only to the extent of the BESS's ELCC, which requires further evaluation to determine its definitive contribution. Please refer to the cover letter to these responses for details regarding the ELCC of BESSs and the use of a BESS as a capacity resource (use case 3).

A 100 MW BESS would limit exposure to Interconnection transfer limitations or curtailments from the NB system (criteria #3), allow the Company to supply a larger portion of its customer load during significant curtailments from the mainland (criteria #4) and increase the Company's ability to backstop renewables (criteria #7), but its effectiveness is limited by the BESS's duration. If a capacity resource is required during these events for a period that is greater than the BESS's capabilities (e.g., more than four hours), the BESS's ability to meet these project justifications is limited. This is not the case for a CT, which can operate indefinitely, as long as fuel is available.

A 100 MW BESS would generally satisfy the need for voltage support during periods of high customer load and transmission system outages (criteria #5).

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[14] As per Table 24 of the December Application Maritime Electric operated its fleet of CTs for a total of 123 hours over the five-year period between 2019 and 2023. 123 / (8,760 x 5) = 0.002

IR-4 Diesel fuel costs.
Please provide MECL's historical delivered diesel fuel costs for CTs on PEI for at least the past 3 years, summarized at a seasonal level (e.g., monthly) or finer granularity, and MECL's projections for delivered diesel fuel cost for the next five to ten years, as data is available.

Response:

Table IR-4i shows the historical delivered diesel fuel costs for Maritime Electric's CTs. The table includes total fuel deliveries, total costs and average delivered costs for all months in which diesel fuel deliveries were received since January 2023.

TABLE IR-4i
Historical Diesel Pricing

Year	Month	Total Fuel Deliveries (cubic meters)	Total Cost ($)	Average Cost ($/l)
2023	January	192	$ 306,811	1.60
2023	February	626	865,193	1.38
2023	November	830	1,103,378	1.33
2024	December	718	905,842	1.26
2025	January	101	148,339	1.47
2025	February	1,451	2,193,386	1.51
2025	March	303	443,256	1.46

Table IR-4ii shows Maritime Electric's projections for delivered diesel fuel quantities and costs for the next five years. The projections are based on the forecasted diesel consumption quantities found in Table 25 of the December 2024 Application.[15]

TABLE IR-4ii
Diesel Consumption and Pricing Forecast

Year	Diesel Consumption (cubic meters)[a]	Average Cost (CAD $/litre)	Total Cost ($)
2026	2,051	$ 1.50	$ 3,066,813
2027	2,349	1.47	3,461,652
2028	2,731	1.41	3,857,787
2029	3,098	1.45	4,493,412
2030	3,387	1.49	5,035,437

a. The average cost per litre is based on United States Energy Information Administration estimations for diesel fuel deliveries to electricity generating plants. An annual escalation rate of 2 per cent was used. A $ USD to $ CAD exchange rate of 1.39 was used for 2026, and 1.43 was used for the years 2027 through 2030. An estimated delivery rate was also added to represent the incremental costs associated with delivery fuel directly to PEI.

15 Forecasted diesel consumption quantities were derived from expected generation requirements and the specific proposed solutions from the December 2024 Application. While final technology selection (e.g., CT versus reciprocating internal combustion engine) may influence diesel consumption, expected variation is not material.

IR-5 Average annual capacity factor of proposed project.

a. Please provide MECL's projected average annual capacity factor for the proposed combustion turbine package for each year from the expected in-service date through 2045, or through the latest year for which projections are available.
b. If MECL has not developed such projections, please explain why MECL considers it reasonable not to have developed projections as part of the project's application process.

Response:

a. Maritime Electric included projections up to the year 2033 as a Generation Requirements Forecast in Table 23 of the December 2024 Application, duplicated below as Table IR-5(a)i. With the exception of "Unit Testing," the forecasted generation requirements are based on system needs and do not directly depend on the specific type, number or size of dispatchable generators added; therefore, the forecast presented in the December 2024 Application is still applicable.

TABLE IR-5(a)i
(Table 23 of December 2024 Application)
Generation Requirements Forecast
(GWh)

Year	Unit Testing	NB Power Hold-to-Schedule	Emergency Energy Supply to Others	On-Island Transmission Related	Curtailment by NB Power	Total	*Per Cent of Customer Energy Supply*
2021A	0.1	1.5	0.4	0.1	0.1	**2.1**	*0.1%*
2022A	0.2	0.4	1.5	0.2	0.2	**2.5**	*0.1%*
2023A	0.1	0.3	0.2	0.2	2.1	**2.9**	*0.2%*
2024A[a]	N/A	N/A	N/A	N/A	N/A	**1.6**	*0.1%*
2025F	0.2	0.7	0.5	0.1	3.3	**4.7**	*0.2%*
2026F	0.2	1.2	0.5	0.1	3.7	**5.3**	*0.3%*
2027F	0.2	1.2	0.5	0.1	4.2	**6.1**	*0.3%*
2028F	0.2	1.5	0.5	0.1	4.8	**7.1**	*0.4%*
2029F	0.2	1.6	0.5	0.1	6.4	**8.7**	*0.4%*
2030F	0.3	1.6	0.5	0.1	8.0	**10.4**	*0.5%*
2031F	0.3	1.6	0.5	0.1	9.9	**12.4**	*0.6%*
2032F	0.3	1.6	0.5	0.1	12.0	**14.5**	*0.7%*
2033F	0.3	1.6	0.5	0.1	14.2	**16.7**	*0.8%*

a. 2024 total was updated with actuals. The breakdown of generation for 2024 is not yet available (NA).

The Generation Requirements Forecast can be used to estimate the average capacity factor of Maritime Electric's dispatchable generation fleet, as shown in Table IR-5(a)ii. The forecast assumes that the 100 MW PE6000 combustion turbines are in service by 2028.

TABLE IR-5(a)ii Average Capacity Factor Forecast			
Year	**Total Generation Requirement Forecast (from Table IR-5(a)i) (GWh) (A)**	**Total On-Island Dispatchable Capacity (MW) (B)**	**Average Capacity Factor (%) (A x 1,000/B x 8,760)**
2021A	**2.1**	89	0.3%
2022A	**2.5**	89	0.3%
2023A	**2.9**	89	0.4%
2024A	**1.6**[a]	89	0.2%
2025F	**4.7**	89	0.6%
2026F	**5.3**	89	0.7%
2027F	**6.1**	89	0.8%
2028F	**7.1**	189	0.4%
2029F	**8.7**	189	0.5%
2030F	**10.4**	189	0.6%
2031F	**12.4**	164	0.9%
2032F	**14.5**	164	1.0%
2033F	**16.7**	149	1.3%

b. 2024 was updated with actuals.

c. Maritime Electric has not developed longer-term projections for generation requirements, as these are anchored to its 10-year load forecast. Forecasting load beyond a 10-year horizon is challenging due to uncertainties in government electrification policies, population growth, economic conditions, and other variables that significantly influence future demand. In addition, future generation requirements will be affected by the amount of renewable energy installed and any changes to the PEI-NB Interconnection transfer limit.

As shown in Table IR-5(a)i, the category "Curtailment by NB Power" increases steadily in the forecast. This trend is expected to persist as load grows, unless and until the PEI-NB Interconnection is upgraded.

IR-6 New Wind.

Provide MECL's planned or expected wind additions by year along with the associated capital cost estimates in CAD $/kW or in $/MWh.

Response:

Maritime Electric does not currently have any plans to develop new on-Island wind generation and, therefore, does not have capital cost projections in CAD $/kW for such projects.

However, as part of the December 2022 Capacity Resource Study, Sargent & Lundy LLC ("S&L") provided an order-of-magnitude estimate for a hypothetical 50 MW onshore wind project, indicating an overnight capital cost of approximately CAD $2,126/kW. S&L has since revised its estimate, projecting a cost of approximately CAD $2,990/kW for a similar project. For more detailed and location-specific capital cost estimates, Maritime Electric suggests contacting the PEI Energy Corporation ("PEIEC"), which has recently constructed and is currently commissioning a 30 MW wind farm in Eastern PEI. Also, given the legislated authority requiring Maritime Electric to purchase energy from PEIEC when directed, PEIEC may be planning or anticipating wind additions that the Company is not yet aware of.

As the transmission provider, Maritime Electric has received multiple interconnection requests from independent proponents seeking to develop wind generation projects and connect to the Maritime Electric transmission system. A summary of these projects was provided in Table 2 (page 22) of the December 2024 Application. The first project in the table (a 30 MW wind farm in Eastern Kings) is currently undergoing commissioning. Additionally, Maritime Electric has received a new interconnection request for an additional 30 MW wind farm proposed in Eastern PEI.

The price of wind energy purchased by Maritime Electric (in $/MWh) is governed by the Minimum Purchase Price Regulations ("MPP") under the *Renewable Energy Act.* Under the MPP, the current minimum purchase price for renewable energy sold to a public utility is $87.124/MWh, which is valid until April 1, 2026. Of this amount, $57.5/MWh is fixed and the remaining $29.624/MWh is subject to annual adjustment based on the All-Items Consumer Price Index for Prince Edward Island, as reported by Statistics Canada.