1. Refer to footnote 2 on page 1 of the Synapse Report. The footnote refers to some – but not all – interrogatory responses filed in this matter.

    a. Please confirm that Synapse has reviewed all interrogatory responses from MECL and the PEI Energy Corporation with respect to this matter.

Response

Synapse has reviewed all interrogatory responses from MECL and the PEI Energy Corporation in respect of this matter. Those include the following:

- MECL response to Stephen Chandler, CEM IRs (1-6), April 25, 2025
- MECL response to Energy Storage Canada IRs (1-3), April 25, 2025
- MECL response to Synapse IRs (1st set, 1-19), May 16, 2025
- MECL response to Synapse IRs (2nd set, 1-6), November 12, 2025
- MECL response to Commission Staff IRs (1-12), January 15, 2026.
- MECL response to additional Commission Staff IRs (13-15), January 28, 2026.
- MECL response to PEIEC IRs (1-18), January 28, 2026
- MECL response (supplemental) to PEIEC IR-9, February 17, 2026
- PEIEC response to Commission Staff IRs (1-16), March 13, 2026

2. Please explain the contingency or contingencies that justify additional on-Island capacity at this time (i.e. disconnection from mainland, extreme weather events, etc.).

    a. How likely are each of these contingencies to occur?

    b. Have these contingencies previously resulted in a service interruption or load shedding for MECL customers? If so, please explain the frequency, duration and impact of the interruption.

Response

Transmission system contingencies, which are forced or unexpected outages of elements of the transmission system, can result in the disconnection of some or (rarely) all of the interconnection capability from New Brunswick and thus reduce the power transfer capacity across the interconnection. An extreme weather event could cause such a transmission system contingency, but transmission contingencies can occur even in the absence of extreme weather events. On-island generation contingencies such as the forced outage of a combustion turbine unit can also occur. Both of these types of contingencies can put pressure on the need for more capacity to be available to meet island load, and this capacity can be located either on or off island.

A separate, non-contingency issue that could justify on-island capacity additions is a shortage of capacity available to flow across the interconnection, even if transfer capability across the interconnection itself is plentiful (for example, the firm interconnection capacity is 300 MW; the concern expressed by MECL is the availability of more than 190 MW from New Brunswick).

a) MECL did not conduct any form of probabilistic analysis to gauge the likelihood of partial or full New Brunswick interconnection disconnection events. In response to a Synapse question (IR-10, 1st set) MECL referenced its response to Synapse IR-8 (1st set) and stated that "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" (IR-10 response, page 17, May 16, 2025). I agree with MECL that the chances of a partial or full disconnection event is low. I think the chances of an extreme weather event over any given planning period (say, 10 years) are relatively high, but that does not imply that such an event will lead to a transmission contingency event.

b) The extreme weather event of February 2023 did not result in firm loss of load. The disconnection event of 2018 did result in loss of firm load, though the reasons included the transmission and distribution system damage, and not just the loss of the interconnection. MECL describes the pattern of loss of load (where it occurred) associated with disconnection events in response to Synapse IR-8 (1st set), Appendix A.

3. There has only been one incident of full disconnection from New Brunswick since the second set of cables were installed in 2017.[1] Neither MECL nor its expert, Sargent & Lundy (S&L), has performed any probabilistic analysis of the chance of partial or full disconnection of the import capacity from New Brunswick. However, MECL states that "*the probability of full and partial disconnection events occurring is low*".[2]

[1] Synapse Report at pages 9-10
[2] MECL response to Synapse IR-10 (Exhibit M-6)

a. Is it appropriate to plan for a contingency that has a low probability of occurring?

b. How probable should a contingency be for capacity planning purposes?

Response

a) In short, it is not appropriate to plan for resource capacity based on a low probability transmission disconnection event occurring at the NB-PEI interconnection. MECL is not doing this in this Application. Its need is premised primarily on the availability of supply from New Brunswick, and its increasing projection of peak load. Resource planning is primarily concerned with the capacity need to meet a peak load forecast.

b) Capacity planning is based on the underlying peak load, not the probability that a contingency event such as interconnection disconnection or extreme weather will occur. The underlying load forecast itself is based on the underlying probability of the province's peak load, and the 50 percent probability is used for that estimation. The reserve margin, which is capacity needed above the peak load forecast, is explicitly needed to address 1) the probability that load will exceed the 50 percent value used in the forecast, and 2) the probability that a resource considered available or firm is not available, due to a forced outage. Resource planning does consider the contingency of a forced outage for a resource, and considers that when accrediting the value of capacity from a resource. For renewable and battery resources, resource planning considers the ability of that resource to be available during peak load conditions.

4. In the 2024 Resource Adequacy Report prepared by New Brunswick Power,[3] the utility states that generation reliability criteria are governed by the loss of load expectation (LOLE) metric. As explained by NB Power, LOLE is a probabilistic calculation of the likelihood of experiencing a loss of load event based on a stochastic analysis of the likelihood that available generation capacity is not sufficient to meet theload demand. The Northeast Power Coordinating Council (NPCC) sets a benchmark of a loss of load expectation of no more than 0.1 days per year.

    a. Is the LOLE metric, and the NPCC benchmark of 0.1 days per year, relevant to MECL's application for on-Island capacity?

    b. If not, what is the applicable metric and/or probabilistic analysis?

[3] NBEUB Docket EL-002-2025, Renewables Integration and Grid Security (RIGS) Project, Appendix A to the Application (Exhibit NBP6.07)

Response

a) The LOLE metric is not particularly relevant to the Application, except that the results for the Maritimes in the NPCC 2025 Maritimes Area Comprehensive Review of Resource Adequacy report confirms that New Brunswick is relatively tight on capacity for the next few years, at least. It should not directly affect how MECL considers procuring resources to meet its share of the overall need.
(https://cdn.prod.website-files.com/67229043316834b1a60feba3/6994b2e9bda14cf9151c5174_2025%20Maritimes%20Comprehensive%20Area%20Review%20of%20Resource%20Adequacy.pdf)

b) The metric that is most relevant is the cost to buy the least expensive overall capacity resource to meet needs, subject to both the 300 MW firm import limit (due to the reliability of the interconnection), and subject to availability to purchase from NB Power.

5. In the Capacity Resource Study, S&L initially recommended a minimum of 85 MW of additional on-Island capacity. However, following the polar vortex in February 2023, S&L recommended that on-Island capacity be increased to 125 to 150 MW.[4] According to MECL, "*Polar vortexes are uncommon and resulted in an abnormally high system peak due to the extreme cold*".[5]

    a. Is it reasonable to rely on an "abnormally high" system peak caused by an "uncommon" event for capacity planning purposes? Please explain.

[4] Addendum to the Capacity Resource Study, Appendix D to the Application (Exhibit M-1)
[5] Application, page 39, footnote 56 (Exhibit M-1)

Response

No, it is not, and MECL does not rely on it, but it may have affected their overall load forecast.

Based on MECL's capacity requirements forecast and their response to Synapse IR-7 (b) (1st set), MECL seemingly does not rely on this abnormally high system peak to plan its capacity needs. MECL states in response to IR-7 (b) that a 50/50 peak forecast is used, along with a reserve margin, for its capacity requirements forecast (i.e., MECL uses the 50 percent probability forecast load, and not the more extreme (lower probability), high system peak value).

It is true that the future system peak used for the capacity requirements has changed since Sargent and Lundy's 2022 Capacity Resource Study (CRS).

Table 9 of the Application shows a capacity requirement in 2032 of 444 MW, which is based in part on an adjusted system peak forecast of 400 MW (net of controllable DSM) in 2032. For comparison, the earlier forecast seen in the Sargent and Lundy CRS (e.g., Table 6-1, page 81) for 2032 was 369 MW, based on an adjusted system peak forecast of 335 MW.

MECL states in Section 5.3.1 of the Application (page 40-41) that its forecast includes the effect of heat pump installations in 2024 and 2025, and planned installations in 2026-2033. Presumably, the projected increase is because of this electrification effect, though MECL does not explicitly state this in the Application.

6. Historically, Maritime Electric has not used the percentage of peak load to determine the amount of generating capacity that should be installed on-Island.[6] 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.

    a. What is the appropriate metric to determine on-Island capacity needs (i.e. percentage of peak load, regional generating capacity, other)? Please explain.

[6] MECL response to Synapse IR-6 (Exhibit M-6)

Response

The appropriate metric is the overall cost of the firm capacity options available to meet the projected requirement (which is based on net peak load plus reserve needs), subject to the reliable firm capacity transfer (300 MW) capability across the interconnection. This would be the least expensive way to meet the requirements.

In this instance, based on what MECL has stated concerning the availability of long-term firm capacity from New Brunswick (i.e., 190 MW) and given MECL's 29 MW share of Lepreau, it implies that the remaining need must come from on-island sources unless or until more New Brunswick capacity is available at costs equal to or lower than on-island alternatives. For example, if MECL's capacity requirement is 454 MW in 2033 (Table 9 of the Application) and 219 MW (firm capacity available, plus MECL's Pt. Lepreau share) can be sourced from New Brunswick, then the remaining 235 MW of need must be sourced from on-island to meet the requirement in that year.

This is 52 percent of the projected requirement in 2033; however, the 52% value is an artifact of the available capacity amounts and not a reliability-based metric. It would be appropriate to procure or obtain this capacity from the least-cost set of those resources available on-island: reductions in peak load (through interruptible loads or demand response), or supply sources such as batteries, renewable resources or combustion turbines.

If additional capacity (in excess of the 190 MW) from New Brunswick became available at costs lower than on-island capacity, and firm capacity transfer headroom remained across the interconnection path, it would be reasonable to procure such increased available capacity.

7. Historically, MECL has used the single highest system peak load (1CP) to allocate costs in its Cost Allocation Studies. However, in its most recent 2023 Cost Allocation Study, MECL used 3CP to minimize volatility associated with the extreme weather conditions during the February 2023 polar vortex.[7]

    a. Please explain whether a similar approach to average the system peak should (or should not) be used for capacity planning purposes.

[7] Commission Docket UE22503 (Rate Design), specifically Exhibit M-13

Response

The existing peak load used in planning for the capacity requirement is based on a projected peak load that is somewhat analogous to an "average" value that could result from a 3CP metric. However, the approach to determine what the peak value should be, for capacity planning purposes, should not be a simple 3CP metric. The basis should remain a formal probabilistic load forecast, with the "50/50" value of that distribution used to determine the peak load for capacity planning purposes. The 50/50 value is that level at which there is a 50% chance that the peak load will be lower, and a 50% chance that the peak load will be higher. Conventionally, it is the midpoint of a normal distribution curve.

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.[8]

    a. Is adding new on-Island generating capacity the least cost option to address MECL's forecast capacity deficit?

    b. If on-Island capacity is not the least cost option, do the reliability benefits of having generating capacity on-Island justify the expenditure? Please explain.

[8] MECL response to Synapse IR-4 (Exhibit M-6)

Response

a) Not necessarily. It is only the least cost option if less-expensive capacity from New Brunswick is no longer available beyond the amounts MECL is currently able to procure.

b) The question is moot, if there is truly no less-expensive New Brunswick capacity increments to procure. If there is less expensive capacity available from off-island, the incremental benefits of on-island capacity would need to be compared to the cost differences between that capacity and the New Brunswick capacity. For example, BESS resources that change the potential pattern and cost of energy purchases from New Brunswick is one benefit. Reliability benefits are more difficult to quantify, since there is not a direct value difference for resources that meet the capacity requirements obligations.

9. MECL states that purchasing capacity and ancillary services from NB Power is not a viable option due to a capacity shortage in the region.[9] Does Synapse agree? Please explain.

[9] MECL response to Synapse IR-2 (Exhibit M-6)

Response

Synapse is not in a position to gauge the accuracy of available capacity in the New Brunswick region, since we do not directly procure or assist entities in procuring capacity, and thus are not well-placed to opine on this question. Our Synapse Final Report relies on MECL's reporting on the opportunities (or lack thereof) of procuring capacity from New Brunswick.

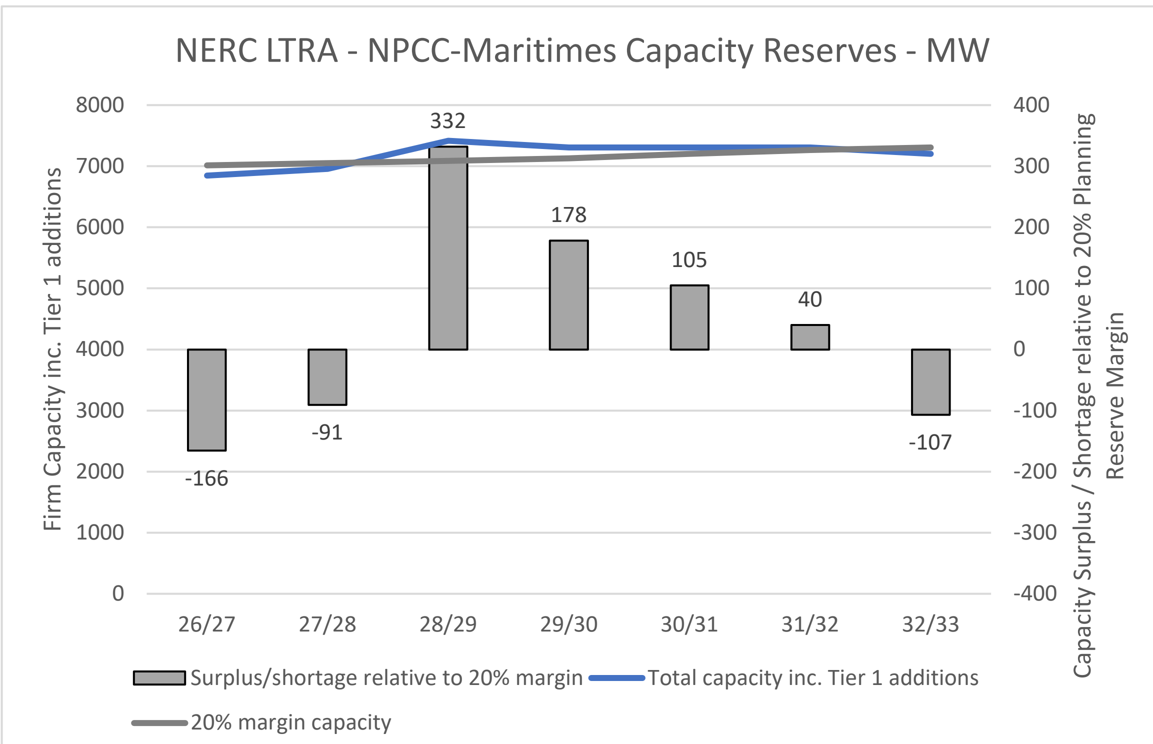
The information contained in the next IR response shows some surplus capacity in the Maritimes region starting with the winter of 2028/29, but the report does not comprehensively convey timing or duration considerations, or actual market availability of such capacity, and thus is not sufficient to support an opinion on the capacity available for purchase.

10. What is the current forecast capacity surplus (or deficit) for the maritime region?

Response

Attachment 1 to this response is the January 2026 NERC LTRA for the 2026/27 through 2035/36 planning years in the NPCC-Maritimes region. Attachment 2 to this response is the NPCC 2025 Maritimes Area Comprehensive Review of Resource Adequacy (December 1, 2025). These documents form the basis for my response.

The current NERC LTRA forecast includes a small capacity deficit for the 2026/27 and 2027/28 winter periods for the Maritimes region relative to the 20% planning reserve margin used by the NPCC for the Maritime region as a whole. The computed shortage in 2026/27 is 165 MW and the shortage in 2027/28 is 91 MW. A capacity surplus is projected to exist starting in 2028/2029, as these data consider the addition of the New Brunswick 400 MW of CT capacity. The graph below summarizes these values.



The NPCC Maritimes Area Comprehensive Review of Resource Adequacy, which covers just the first five winter periods (January 2025 through December 2030, but with January 2030 being the peak month in that year), shows a similar pattern as the NERC LTRA report. It reflects a slight shortage in the first two periods, and surplus thereafter. It provides results for a base case load considering the loss of load expectation (LOLE) metric, and a separate “forecast reserve” metric.

11. In 2015, Maritime Electric sought Commission approval to purchase and install a 50 MW combustion turbine.[10] The application was withdrawn to allow MECL to focus on expanding the New Brunswick-PEI Interconnection.[11] Today, the NB-PEI Interconnection remains a limiting factor in transmission capacity to PEI. Although the physical capacity of the four subsea cables is 560 MW, the Interconnection capacity is limited to 300 MW.

    a. Is improving the NB-PEI Interconnection to increase transmission capacity above 300 MW a reasonable alternative to on-Island generation? Please discuss and consider the cost, reliability, and anticipated availability of capacity in the region.

[10] Commission Docket UE20723
[11] Application, page 17, footnote 16 (Exhibit M-1)

Response

No, improving the NB-PEI interconnection capacity above the firm 300 MW level is not a reasonable alternative to on-island capacity at this time. There is currently headroom on the existing interconnection, but it cannot be utilized because there is insufficient capacity available for purchase. The cost of new capacity external to PEI would need to be less expensive (by an amount equal to the cost of the incremental interconnection capacity to PEI) than capacity on-island for this to be a reasonable alternative.

12. MECL's current Energy Purchase Agreement with NB Power expires on December 31, 2026. In its Application, MECL has assumed that NB Power will maintain its current contracted firm capacity (190 MW), but that no additional firm capacity will be available to MECL in 2027 and subsequent years. However, new capacity has been planned for the region since the Application was filed in December 2024.

    a. In the event that MECL can secure additional firm capacity (more than 190 MW) from NB Power, is MECL's target of having 50 percent of its capacity requirements on-Island still reasonable? Please discuss.

Response

The 50% target remains reasonable, but not rigidly so, as a reliable and economic capacity structure can be in place even if the on-island percentage is lower. If NB Power has increased availability of capacity beyond 190 MW, it would be prudent for MECL to review the quantities, the timing and the costs for that capacity and compare that to the costs and benefits of on-island capacity.

The overall cost to meet capacity requirements remains the key factor to consider.

Other factors include the planned (or potential) retirement of 40 MW of CT capacity at Borden in 2030 and 2032, the importance of on-island BESS capacity in support of PEI's overall energy policy goals over the near and long-term, and the quantity, timing and available duration of any such capacity (e.g., long-term capacity or short-term capacity).

13. Since the Application was filed in December 2024, a new 500 MW generating facility has been planned for New Brunswick. Is purchasing additional capacity from this planned facility a reasonable alternative to on-Island capacity? Please discuss.

Response

Yes, to some extent. MECL must review the cost, availability and details of such a potential procurement. See the previous response to Commission Staff IR-12.

14. In its Application, MECL states that "*As the cost to source and install these units will be relatively similar across Atlantic Canada, the cost of purchasing additional capacity from off-Island resources is expected to be comparable to the cost of building additional on-Island generating capacity resources*".[12]

[12] Application, page 86 (Exhibit M-1)

a. Does Synapse agree with this statement?

b. Are there additional costs associated with owning a capacity asset? Please explain.

c. Is there a financial benefit for MECL to own the asset, compared to purchasing off-Island capacity? Please explain and provide any supporting calculations.

Response

a) Synapse is not in a position to directly compare the costs for capacity available in the New Brunswick market or region, with those costs for directly building the same capacity on-island, except to the extent we have already done so as part of our Synapse Final Report. See the response to Commission Staff IR-9. Our Synapse Final Report relies upon MECL's estimates for capacity costs.

b) There are costs associated with owning a capacity asset, e.g., primarily operation and maintenance costs (in addition to any financing or tax effects, depending on how the overall capital cost accounting is carried out). However, procurement of capacity from another party usually factors in those costs (which are borne by the seller) in the price of the capacity. A direct quantitative comparison, including all details, must be completed to assess which option is better for ratepayers. For this Application, the different types of capacity matter. As our Synapse Final Report describes, the overall economics of BESS capacity is intrinsically tied to the cost of energy required to charge the battery, and the value of energy when discharging the battery.

c) See the response to b) above.

15. According to S&L, a battery energy storage system (BESS) can be used to shift load but not to generate electricity. In the event of a disconnection from New Brunswick, are there reliability risks associated with BESS as a capacity resource compared to a CT or a RICE? Please explain and discuss specifically the impact of the state of charge and the duration of the outage.

Response

Yes, there are reliability risks for a BESS resource associated with the state of charge and the duration of the outage. However, those risks cannot be gauged in isolation. The other factors that must be considered include:

- the nature of the disconnection (full, or partial);
- the timing of the disconnection and the load pattern on the island at the time;
- if any advance notice informed posturing of resources (such as planning for an extreme weather event); and
- the status of the available on-island resources (wind and others).

All of these factors influence the assessment of risk of this resource, relative to a CT or RICE resource. Under a full disconnection, if it occurs during high load periods, the loss of load is likely to be severe regardless of whether the on-island capacity is BESS or CT/RICE additions, since the intention is not to have the island support 100% of peak load operation in isolation from New Brunswick. Under a partial disconnection, the flexibility of the BESS resource and the continued availability of both wind energy and New Brunswick import energy must also be considered.

A CT or RICE resource has the risk of an outage, or unavailability. For example, in the one full disconnection event that has occurred since the new cables were installed, the CT resources tripped offline or were not fully available during the 8-hour outage.

As described in our Synapse Final Report, the risks of a duration or state-of-charge related concern with BESS resources must be considered along with the benefits that BESS resource conveys as a flexible, dispatchable resource with the ability to maintain voltage and frequency on the island, and support the ongoing use of wind turbine operation during a disconnection event.

16. Assume there is an extreme weather event, such as a polar vortex, and either the wind is not blowing or the turbines are offline. In this scenario, which on-Island capacity resource (or mix of capacity resources) is most effective/reliable?

Response

Under the conditions posed all on-island resources, existing or new, would be called upon to complement any supply coming from New Brunswick during the event. The effectiveness and reliability of any BESS resource would depend on its overall energy storage capability (in MWh) and how long the event lasted; what the hourly pattern of load is during the event (and if any load is disconnected due to on-island transmission or distribution outages); and what the New Brunswick supply availability pattern was during the event. It would also depend on the state of its charge at the start of the event. The effectiveness and reliability of a CT or RICE resource would depend on its ability to start, and/or remain online, and not be forced out of service during the extreme weather event.

The BESS resource effectiveness during an extreme weather event is tied to the availability of on-island wind resources or import availability during and prior to the event. Any limitations on these sources of charging energy would reduce the ability of the BESS resource to be maximally effective. The CT or RICE resource effectiveness during such an extreme event would be tied to its overall availability and likelihood of undergoing a forced outage event during the extreme weather event.

It is not possible to state with any certainty which resource would be "most effective/reliable" because the full context of the scenario in question is not provided; i.e., what are the load patterns over the period in question, what is the level of available supply from New Brunswick and thus what is required from on-island resources, and what are the expectations of when wind and wind turbine operation would return to service.

17. Assume the PEI electrical grid is disconnected from New Brunswick for an eight-hour period, as it was in November 2018. In this scenario, which on-Island capacity resource (or mix of capacity resources) is most effective/reliable?

Response

Determining which mix of resources would be most effective/reliable during an eight-hour disconnection event would depend in part on the sequence of events leading up to the disconnection, and in part based on conditions on the island during the disconnection event. Those conditions include the actual load, the status of the on-island transmission system, the availability of wind generation during the event, and the availability of existing or new CT resources and new BESS resources.

Based on the sequence that actually occurred in 2018 (MECL response to IR-8, 1st set, Appendix B), where start up and tripping events occurred for CT resources, and extensive load loss occurred prior to the disconnection due to on-island transmission trips, the flexibility of having a battery energy system in addition to the CT resources would have been useful.

The most effective mix of resources would provide flexibility of operation to allow operators to adjust to system conditions such as:

- the actual amount of load (since considerable load might be offline due to distribution or on-island transmission issues separate from any generation or battery resource condition or interconnection condition);
- the actual status of wind generation resources;
- the status of the on-island transmission system; and
- the status of BESS resources that would be able to provide voltage and frequency support for the island.

18. Synapse concludes that both the proposed CT project and a BESS resource alternative fully support MECL's "use case" for on-Island capacity.[13]

    a. Assume that MECL will install 150 MW of additional on-Island capacity. What is Synapse's opinion on the optimum resource mix? Please discuss and explain.

    b. Please comment on a scenario in which 100 MW of capacity is from CTs (as proposed in MECL's August 2025 Supplemental Filing) and the remaining 50 MW is from a BESS.

[13] Synapse Report at pages ES-1, 56

Response

a) The optimum resource mix for 150 MW of on-island capacity addition should be determined through a more careful examination of the capacity and energy costs of the alternatives than MECL has done thus far, over a reasonable investment planning horizon such as 20 years. This exercise should consider BESS resources of different durations, wind resources, solar PV resources, CT and RICE alternatives, and the ability to increase either or both of interruptible load or demand response from existing load. Without fully analyzing these alternatives in at least a somewhat structured manner, especially including the effect of considering new renewable energy resources that may be deployed on Prince Edward Island, it is impossible to say with any degree of certainty what the optimum mix would be.

   As noted in our Final Report at page 4, in our analysis in 2022 we found that it was cost-effective to plan for increased battery energy storage on PEI to address capacity needs. It also showed that increases in wind supply were cost-effective under scenarios where New Brunswick energy prices were higher than the base assumptions, or if PEI implemented more stringent requirements for renewable resource requirements

   Based on the initial analysis we conducted in support of our Final Report, the first 100 MW of new capacity resources on-island from BESS resources is less costly than the CT alternative. In my opinion, this would be the best, first tranche of additional capacity to add to the existing on-island resources at this time.

   The best second tranche, excluding peak load reduction or mitigation for the purpose of this answer, in my opinion, is likely to be a combination of new wind and additional BESS resources.

   The second tranche of capacity addition should carefully consider the costs of additional batteries and their energy interaction with additional wind or solar resources and compare those costs to the CT or RICE alternatives. As noted, the capability of new demand-side programs (such as demand response to mitigate peak load increases from electrification) should not be overlooked. Critically, MECL should not rush to determine the best mix after deploying a first tranche of on-island capacity.

b) A scenario with the first 100 MW of on-island capacity from the new CT project would not be in the best interest of ratepayers because it is more expensive and does not capture any of the synergistic energy benefits associated with the BESS resource. It is, at best, a second-best choice. A further increment of 50 MW of BESS resource does not make the selection of the CT for the first 100 MW increment any more economical.

19. In its report, Synapse discusses how a BESS can be used to shift load and reduce winter net peaks. In this way, can a BESS be used as a resource to minimize, reduce or defer capital expenditures associated with peak demand? Please explain.

Response

Yes, a BESS resource can be utilized to reduce or defer capital expenditures associated with requiring generation capacity to meet peak load. Depending on the connection point and project design and intention, some BESS resources could also be used to reduce or defer capital costs associated with transmission and distribution system capital expenditure needs by reducing the net peak load seen on those electric system elements.

The BESS resource itself, at utility-scale (e.g., installed at the Charlottetown plant site) does not reduce the peak load on the system, but in general it can reduce the peak load (net of the BESS resource output) required to be served by other generation resources (or served through imports, demand response or interruptible load). Thus, it can serve as a replacement or an alternative to a new capacity resource. Also, the BESS resource used on a regular basis by MECL to “hold to schedule” for New Brunswick energy purchases can reduce the need for use of existing combustion turbine operation required to meet this need. Thus, it could potentially defer expenditures (or, possibly, defer retirement) for existing CT resources that will require less operation on a regular basis for this service if the BESS resource was deployed for this service.

Distribution and transmission system planning can consider targeted location of BESS resources to reduce the peak loading on system elements that might otherwise need to be upgraded or replaced. Careful and extensive planning is required to consider this benefit from BESS resource deployment.

20. Since the Application was filed in December 2024, the Federal Government has introduced Clean Electricity Regulations (CER) that aim to create a net-zero electricity grid by 2050.

    a. What impact do (or should) government policy and regulations have on new capacity resources?

    b. In its Capacity Resource Study, S&L discusses the risk of stranded assets if Canadian regulations change the allowable fuels for electricity generation. Please explain the risk and implications of a stranded asset for both MECL and its customers.

Response

a) The purpose and the intended effect of the Clean Electricity Regulation is to disincentivize investment in greenhouse gas (GHG) emitting energy resources. GHG emissions are tied to energy, not capacity; however, the selection of a GHG-emitting capacity resource implies that when it is needed for reliability, it would emit GHGs. This is the case for the CT project, as MECL describes in Section 9.0 of the Application. MECL notes, however, in section 9.5 that its project would be exempt from the CER regulation (in draft form). It is my understanding that this is also the case for the full, final CERs since the project would be in place before 2035; and this is also likely the case for the planned changes to the CERs (a potential relaxation) based on a May 2026 update from the Canadian government (https://natural-resources.canada.ca/energy-sources/electricity-infrastructure/powering-canada-strong-national-strategy-electrified-canadian-economy). However, the "net zero by 2050" will remain as part of the CER, and any consideration of use of new fossil fuel resources on MECL's system should continue to account for this aspect of the regulation, especially any forward-looking assessment with a planning horizon out to 2050, in addition to the underlying economics addressed in the Synapse Final Report.

b) In short, the risk and implications of a stranded asset for MECL customers is that those customers would essentially have to pay for an asset that no longer provides sufficient value (in capacity or energy form) to cover its costs.

   S&L notes in the CRS (at Section 5.2.4, 5.2.5, and other locations) that either a new RICE unit or a new CT would be less likely to become a stranded asset (if regulations restricted the use of fossil fuels) because they both can use renewable fuels (RICE units directly; CT units with some additional capital costs). Renewable fuel for a new combustion unit would likely cost more, or at least as much as, the diesel fuel they would run on upon installation. A stranded asset is a resource whose going-forward costs are more than the going-forward value it provides. If a new CT or RICE unit was no longer allowed to burn fossil fuel, it would not be a useful capacity resource unless it was able to then burn renewable fuel. In this instance, it does not appear that the fuel issue alone would render either a CT or a RICE unit a potential stranded asset because it could still provide capacity value (even if the energy costs were much higher with renewable fuels).