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MARITIME ELECTRIC
A FORTIS COMPANY



October 22, 2021

Island Regulatory & Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Commissioners:

**2022 Capital Budget Application – Docket UE20733**
**and 2020 Integrated System Plan – Docket UE21227**
**Response to Interrogatories from Synapse Energy Economics Inc.**

Please find attached the Company's response to Interrogatories from Synapse Energy Economics Inc. with respect to the 2022 Capital Budget Application filed on July 14, 2021 and the Company's 2020 Integrated System Plan filed on September 30, 2020. An electronic copy will follow shortly.

Yours truly,

MARITIME ELECTRIC

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# I N T E R R O G A T O R I E S

## Responses to Interrogatories
## of
## Synapse Energy Economics Inc.

## 2022 Capital Budget Application (UE20733)
## and
## 2020 Integrated System Plan (UE21227)

**Submitted October 22, 2021**

**Data requests for Maritime Electric Company, Limited (MECL)**

At a high-level, the requests that follow are asking for all the fundamental inputs that Maritime Electric Company Ltd (MECL) used in its Integrated System Plan (ISP) analysis, and in support of its 2022 Capital Budget Application (including inputs for any model runs that may have been done), across demand-side, supply-side and transmission and distribution categories. Additional data requests may be forthcoming after review of the responses to these initial questions.

Please provide all quantitative data requested in electronic, machine-readable format (preferably Excel). Please provide all spreadsheets and workpapers with formulae intact.

For all dollar values please indicate whether they are real or nominal. We presume all values are in Canadian dollars – confirm or explain otherwise (e.g., $US) if this is not the case.

Responses are requested within 15 business days from receipt of this request. Synapse requests piecemeal delivery of responses for those responses that can be completed earlier than in 15 business days.

If the data requested is not available, please indicate this in the response, explain briefly why it is not available, and provide the best available alternate source of data. Synapse can sign a non-disclosure agreement (NDA) or other confidentiality documents as necessary in order to receive data, if necessary for any confidential data. This has been a matter of standard practice in many jurisdictions where we request utility data.

Capital Budget Allocation

IR-1 From Maritime Electric's 2022 Capital Budget Application, approximately 40% ($16 million) of proposed expenditures are associated with access and system growth. Approximately, 86% ($14 million) of these expenditures correspond to the distribution system.

a. Has Maritime Electric analyzed how more aggressive demand side management strategies, such as deploying energy efficiency and demand response or distributed energy resources (e.g., battery storage, and solar PV) could reduce system load and potentially defer or eliminate the need for a percentage of capital expenditures? If so, provide all analysis of the sensitivity of capital requirements to the peak load trajectory (in total, or by feeder) across PEI.
b. If not, explain why not.

***Response:***

a. No, as explained in the response to IR-1b below.

b. The Government of Prince Edward Island delegated primary responsibility for demand-side management ("DSM") programming to efficiencyPEI in 2017. Maritime Electric has since limited its involvement in DSM to activities that support efficiencyPEI strategies and programs.

A consultant was recently engaged by efficiencyPEI to develop its next three-year Electric Efficiency and Conservation ("EE&C") Plan, which is expected to be completed in the fourth quarter of 2021 and then submitted to the Island Regulatory and Appeals Commission for regulatory approval.

Maritime Electric will contribute to the development of the new EE&C Plan by providing technical input and data to efficiencyPEI's consultant, upon request. The forecast load reduction impact of the approved EE&C Plan will be included in future Maritime Electric peak load forecasts.

IR-2 Potential new CT in 2025. (Appendix A, Summary of Actual and Proposed Capital Expenditures (2013 to 2026), 2025 and 2026 entries of $45 and $46 million for Combustion Turbine #4).

a. Has Maritime Electric conducted an analysis to determine whether a combination of distributed energy resources (e.g., battery storage, and/or battery storage plus solar PV) and demand response resources (and/or increased energy efficiency effects) could obviate or defer the need to build a new combustion turbine by 2025, or reduce the need to purchase additional capacity from New Brunswick? If so, please provide all such sensitivity analyses.

b. If not, explain why not.

***Response:***

a. No, as explained in the response to IR-2b below.

b. Maritime Electric last assessed the need for a fourth combustion turbine ("CT4") to provide on-Island generation capacity prior to submitting an application for CT4 to the Island Regulatory and Appeals Commission in June 2015. The CT4 application was subsequently withdrawn in July 2016, after the PEI-NB Interconnection Upgrade Project was confirmed and the firm transmission capacity from New Brunswick to the Nova Scotia/PEI interface was increased.

Maritime Electric has generally kept abreast of developments in combustion turbine generation, renewable energy with battery storage, generation alternatives including distributed energy and demand response resources, and the potential for increased energy efficiency effects; however, because generation capacity limitations have not yet reached the point where a new combustion turbine is required, the analyses to determine the best long-term solution has not yet been conducted.

Within a reasonable advance timeframe of when additional generation capacity is required, Maritime Electric intends to undertake a full study of all the options available and determine the best long-term solution. This study is proposed in Section 4.2 of the 2022 Capital Budget Application as the On-Island Generating Capacity Study.

Integrated System Plan (ISP):

IR-3 Tables 5 (p. 16) and 12 (p. 27) contain energy and peak load data for PEI.

a. Please confirm or explain otherwise that MECL's ISP is based on a single energy and peak load forecast, as seen in Tables 5 and 12.
b. To what extent has Maritime Electric considered the potential demand-side impacts of an updated electricity efficiency & conservation plan (EE&C plan) in any of its analysis for an integrated system plan?
c. If MECL has considered the potential demand-side impacts of a new EE&C plan, please provide MECL's assessment. If not, please explain why not.

***Response:***

a. Yes, Maritime Electric's Integrated System Plan ("ISP") is based on the energy and peak load forecast as seen in Tables 5 and 12 of the ISP.

b. Maritime Electric included known demand-side management ("DSM") programming in its load forecast up to 2022. After 2022, Maritime Electric assumed a constant incremental annual reduction in system energy consumption, at the same level as forecast for 2021, for both Residential and General Service rate classes (see Excel spreadsheet IR-3 – Attachment 1; 'DSM' worksheet; columns B and D; rows 12 through 23).

c. Maritime Electric has not considered the impacts of a new Electric Efficiency and Conservation ("EE&C") Plan as it is still under development by efficiencyPEI. Additional information on the status of the new EE&C Plan is provided in the response to IR-1b.

IR-4 MECL states "Programs to encourage off-peak charging will help minimize the impact on existing infrastructure and will encourage more efficient use of the system" (page iii) and also states "a failure to achieve widespread off-peak charging will lead to large infrastructure increases and associated costs to enable charging during peak periods" (page i). Table 4 (page 15) contains a PEI Electric Vehicle forecast.

a. Does MECL's projection of peak load as seen in Tables 5 and 12 presume "Maximum Peak Impact (MW)" from EVs, as seen in Table 4?
b. What level of peak load increase does MECL assume from heat pump installations on PEI, over the 2021-2030 timeframe?

***Response:***

a. No. In Maritime Electric's forecast, peak load is determined by taking the annual energy sales (plus losses) and applying a load factor. While EV charging energy has been included in the annual energy sales forecast, the values shown in the Maximum Peak Impact column of Table 4 (in the Integrated System Plan) were not used directly in the peak load forecast.

b. Maritime Electric's forecast space heating load at system peak over the 2021 to 2030 timeframe is shown in Table 1 below.

**Table 1**
**Forecast Space Heating Load at System Peak 2021 to 2030**

| Year | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Space Heating Load (MW)** | 68 | 73 | 78 | 83 | 87 | 92 | 97 | 102 | 106 | 109 |

The forecast space heating load is based on the assumed continuation of efficiencyPEI's program to incentivize the installation of heat pumps in existing dwellings. Approximately 4,000 heat pumps were installed in 2020 through this program, which is consistent with the number of installations in previous years. Approximately 20 per cent of these heat pumps were installed in dwellings that were primarily dependent upon resistive electric baseboard heaters, while the remaining 80 per cent were installed in dwellings using other energy sources for space heating including furnace oil, wood and propane. This has been the general trend for the past several years, as indicated by efficiencyPEI.

New construction is also contributing to the forecast space heating load shown in Table 1, as Maritime Electric estimates that 95 per cent of new housing starts install electric-based space heating, and 80 per cent are estimated to be heat pump installations. Typically, single-detached and semi-detached dwellings install two heat pumps with supplementary resistive baseboard heating, while other dwelling types often install baseboard heating as the primary heat source, with a single heat pump to offset a portion of the resistive baseboard electricity consumption.

Housing starts for PEI in 2019 and an estimate of associated new heat pump installations is shown in Table 2.

| Table 2<br>PEI Housing Starts and Associated Heat Pump Installations for 2019 | | |
|---|---|---|
| | **Housing Starts[a]** | **Heat Pump Installations[b]** |
| efficiencyPEI incentive program | | 4,000 |
| Single-detached | 480 | 768[c] |
| Semi-detached and duplex | 125 | 200 |
| Row housing | 163 | 130 |
| Apartments and others | 736 | 589 |
| **Total** | **1,504** | **5,687** |

a. Prince Edward Island 46th Annual Statistical Review 2020; Table 61 - *Housing Starts by Type of Unit, 2008-2019*
b. Does not include heat pumps installed by businesses.
c. Single-detached homes = 480 houses x 80 per cent penetration x 2 heat pumps per house.

The average temperature at the December system net peak on PEI over the 2010 to 2019 timeframe was -9.0ºC, as shown in Table 3.

| Table 3<br>PEI Average Temperature at the December System Net Peak 2010 to 2019 | | | | | |
|---|---|---|---|---|---|
| **Year** | **PEI Total (MW)** | **December Peak Date** | **Day of Week** | **Hour Ending** | **Temperature (ºC)** |
| 2010 | 206.1 | 20 | Mon | 18:00 | 2.2 |
| 2011 | 220.8 | 20 | Tue | 18:00 | -6.1 |
| 2012 | 228.4 | 10 | Mon | 18:00 | 0.2 |
| 2013 | 251.8 | 12 | Thu | 18:00 | -15.4 |
| 2014 | 254.5 | 30 | Tue | 18:00 | -14.5 |
| 2015 | 240.6 | 28 | Mon | 18:00 | -10.1 |
| 2016 | 264.2 | 16 | Fri | 18:00 | -15.9 |
| 2017 | 278.4 | 27 | Wed | 18:00 | -14.8 |
| 2018 | 269.8 | 27 | Thur | 18:00 | -10.2 |
| 2019 | 275.2 | 16 | Mon | 18:00 | -5.3 |
| | | | | **Average** | **-9.0** |

The incentives offered by efficiencyPEI are only applicable to air source heat pumps that meet the Northeast Energy Efficiency Partnerships Cold Climate Air-Source Heat Pump Specification, which generally work to at least -25ºC. As such, Maritime Electric assumes that all new heat pumps are still operating in heat pump mode, rather than resistive mode, at the time of system (winter) peak.

A new heat pump typically has a full load draw of approximately 2,000 watts. At the present installation rate in PEI, and if all the new heat pumps are operated at full output during winter peak, the result would be an 11.4 megawatt ("MW") increment in system peak load each year, all else being equal. Usage diversity makes this unlikely; however, if even half of the new installations are operating at system peak, an additional load of 5.7 MW would be experienced annually. As such, Maritime Electric believes the majority of the forecast increase in space heating load is due to heat pump installations.

IR-5 To what extent is MECL planning to reduce peak load increases from electrifying load (i.e., EV and heat pumps) using new AMI meter technology? Please provide any estimates of peak load avoidance MECL may have based on current analyses.

***Response:***

The potential for advanced metering infrastructure ("AMI") technology to reduce peak load increases associated with the electrification of heating and transportation in PEI has not yet been estimated by Maritime Electric.

The ability of AMI to support time-of-use ("TOU") metering presents one of the best opportunities to change customer consumption patterns for reducing system peak load. With TOU metering, AMI interval consumption data can be grouped into rating periods, in accordance with a TOU rate structure, to enable the recording of electricity usage at certain times of the day, week, or year. During periods of the day when customers typically consume a greater amount of electricity, customers are charged a higher rate than during periods of the day with lower consumption. Normally TOU is divided into three segments: off-peak (low demand), mid-peak (moderate demand), and on-peak (high demand).

Once AMI is deployed, it is recommended that interval data be monitored, target outcomes be established with external stakeholders and appropriate rates be proposed for regulatory approval. Stakeholders will also be provided the opportunity to provide input into the development of new tariffs; however, the details of how this will occur have not yet been planned.

IR-6 Actual and Forecast Off-Island Energy and Capacity Source Costs:

Referencing 1) "Maritime Electric sourced 78 per cent of its energy supply from off-Island sources in 2019, including 16 per cent from a long-term participation stake in NB Power's Point Lepreau Nuclear Generating Station, and the rest through an all-services energy purchase agreement ("EPA") with NB Energy Marketing ("NBEM"). The current EPA expires in 2024". (p. 17). Table 13 Actual and Forecast Energy Sources (p. 29). Table 15 Actual and Forecast Capacity Options (p. 32). And, "[MECL] will continue to procure the bulk of its energy from the mainland as it is more economic than on-Island dispatchable resources, …" (page 43):

a. Table 13 and Table 15 contain actual and forecast energy and capacity from NB system purchases for 2018-2025. Please provide the projected New Brunswick energy and short-term capacity system purchases in GWh and MW from 2026-2040. If no explicit estimate exists, provide MECL's best indications for expected levels in that time frame, and include the key underlying factors that inform MECL's estimation.
b. For actual purchases of NB system energy and short-term NB capacity purchases in 2018 and 2019 (and 2020 if available), provide the total costs in each of the years for those purchases.
c. For Table 13 and Table 15 forecast purchases of NB system energy and short-term NB capacity purchases in 2020 through 2025 (or in 2021 through 2025, if 2020 has been provided under "actual") provide the estimated total costs in each of the years for those forecast purchases.
d. For actual purchases of NB system energy and short-term capacity in 2018 and 2019 (and 2020 and 2021 to-date if/as available), provide the actual or estimated hourly costs for those purchases for each and all hours. If actual costs are not available or not applicable on an hourly basis, provide monthly, seasonal, on-peak/off-peak, or other granular information to convey the pricing terms associated with the purchased energy and capacity.
e. For forecast purchases of NB system energy and short-term capacity in 2020 through 2025 (or from 2021 forward if 2020 costs have been provided as "actual"), provide the estimated hourly costs for those purchases for each and all hours. If costs are not available or not applicable on an hourly basis, provide monthly, seasonal, on-peak/off- peak, or other granular information to convey the pricing terms associated with the purchased energy and capacity.
f. For projected energy and system capacity purchases from NB in the 2026-2040 time frame (i.e., for quantities from the response to part a. of this question) provide an estimate of the costs of those purchases in total by year, and describe MECL's expectations for how those costs will vary by hour, month, season, on-peak/off-peak period, as applicable for each of energy and capacity products.
g. Provide any further information as necessary to fully convey the nature of the costs for off-island (NB) energy and capacity purchases, and how those costs have varied or are expected to vary in the future, by hour, month, season, period, or contracted product definition.

***Response:***

a. The energy and capacity requirement estimates provided in this response to IR-6a, reflects the load forecast developed in January 2020, which was used as the basis for the Integrated System Plan ("ISP").

The projected New Brunswick Power Firm, Secure and Assured Energy products and Short-Term Capacity ("NB System Energy and Capacity") requirement estimates for the years 2021 to 2030 are shown in Tables 1 and 2, respectively. Energy amounts are shown in gigawatt-hours ("GWh") and capacity amounts are in megawatts ("MW").

**Table 1**
**Projected NB System Energy Purchases 2021 to 2030 (GWh)**

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| Charlottetown Steam Plant | - | - | - | - | - | - | - | - | - | - |
| On-Island combustion turbines | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| PEI Energy Corporation | 361 | 420 | 420 | 420 | 499 | 583 | 583 | 583 | 583 | 583 |
| Customer-owned | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 |
| Point Lepreau | 215 | 215 | 215 | 215 | 215 | 215 | 215 | 215 | 215 | 215 |
| NB System Energy purchases[a] | 906 | 882 | 915 | 947 | 899 | 854 | 876 | 907 | 938 | 967 |
| **Total energy[b]** | **1,489** | **1,525** | **1,560** | **1,593** | **1,625** | **1,656** | **1,688** | **1,720** | **1,752** | **1,782** |

a. NB System Energy purchases include Firm, Secure and Assured Energy products.
b. Totals are rounded.

Due to the current uncertainties around a fourth combustion turbine ("CT4") being added Maritime Electric's on-Island supply system, CT4 is not included in the listing of Maritime Electric capacity resources in Tables 2 and 4. Instead, capacity requirements are assumed to be fulfilled through NB Short-Term Capacity purchases

**Table 2**
**Projected NB Short-Term Capacity Purchases 2021 to 2030 (MW)**

| Maritime Electric Planning Capacity Requirement: | | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Maritime Electric peak load | | 275 | 283 | 291 | 299 | 306 | 313 | 321 | 328 | 335 | 341 |
| Less interruptible load | | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) |
| Plus 15% planning reserve | | 39 | 40 | 42 | 43 | 44 | 45 | 46 | 47 | 48 | 49 |
| **Total** | | **300** | **309** | **318** | **327** | **336** | **344** | **353** | **361** | **370** | **376** |
| Maritime Electric Capacity Resources: | | | | | | | | | | | |
| Charlottetown Steam Plant | | 38 | - | - | - | - | - | - | - | - | - |
| Borden Plant | | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 |
| Combustion Turbine 3 | | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 |
| Point Lepreau | | 29 | 29 | 29 | 29 | 29 | 29 | 29 | 29 | 29 | 29 |
| NB Short-Term Capacity purchases | | 120 | 170 | 180 | 190 | 195 | 200 | 210 | 220 | 230 | 235 |
| **Subtotal** | A | **276** | **288** | **298** | **308** | **313** | **318** | **328** | **338** | **348** | **353** |
| Purchased Wind Capacity: | | | | | | | | | | | |
| Maritime Electric purchased wind nameplate capacity | B | 122 | 122 | 122 | 122 | 162 | 162 | 162 | 162 | 162 | 162 |
| Effective Load Carrying Capacity ("ELCC") as % of nameplate | C | 20 | 20 | 20 | 20 | 16 | 16 | 16 | 16 | 16 | 16 |
| ELCC | D = B x C | 24 | 24 | 24 | 24 | 26 | 26 | 26 | 26 | 26 | 26 |
| **Total** | **E = A + D** | **300** | **312** | **322** | **332** | **339** | **344** | **354** | **364** | **374** | **379** |

The projected NB System Energy and Capacity requirement estimates for the years 2031 to 2040 are shown in Tables 3 and 4, respectively. Energy amounts are shown in gigawatt-hours (GWh") and capacity amounts are in megawatts ("MW").

**Table 3**
**Projected NB System Energy Purchases 2031 to 2040 (GWh)**

| | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|
| Charlottetown Steam Plant | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Combustion turbines | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| PEI Energy Corporation | 578 | 578 | 578 | 578 | 578 | 578 | 578 | 578 | 578 | 578 |
| Customer-owned | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 17 |
| Point Lepreau | 215 | 215 | 215 | 215 | 215 | 215 | 215 | 215 | 215 | 215 |
| NB System Energy purchases[a] | 1,006 | 1,043 | 1,080 | 1,117 | 1,156 | 1,195 | 1,235 | 1,276 | 1,318 | 1,361 |
| **Total energy[b]** | **1,817** | **1,854** | **1,891** | **1,928** | **1,967** | **2,006** | **2,046** | **2,087** | **2,129** | **2,172** |

a. NB System Energy purchases include Firm, Secure and Assured Energy products.
b. Totals are rounded.

The estimates in Table 3 and 4 are based on the following assumptions:

1. Maritime Electric's forecast energy requirement growing at 2.0 per cent annually between 2031 and 2040;
2. Maritime Electric's peak load growing at 2.2 per cent annually between 2031 and 2040;
3. No replacement of the Charlottetown Thermal Generating Station;
4. Continued use of existing combustion turbines CT1, CT2 and CT3 primarily for backup and emergency supply purposes;
5. The PEI Energy Corporation not building any additional renewable energy generation facilities after 2026, and all existing renewable energy generation that reaches end of life being immediately replaced by generation with a similar capacity and capacity factor;
6. Customer-owned generation leveling off after 2030;
7. Point Lepreau continuing operation until 2040;
8. New Brunswick Energy Marketing ("NBEM") continuing to provide the balance of the energy supply; and
9. Maritime Electric replacing its 40 MW Borden generating facilities (i.e., CT1 and CT2) in 2031 with generation totaling 60 MW.

| Table 4<br>Projected NB Short-Term Capacity Purchases 2031 to 2040 (MW) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Maritime Electric Planning Capacity Requirement: | **2031** | **2032** | **2033** | **2034** | **2035** | **2036** | **2037** | **2038** | **2039** | **2040** |
| Maritime Electric peak load | 348 | 356 | 364 | 372 | 380 | 388 | 397 | 406 | 415 | 424 |
| Less interruptible load | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) |
| Plus 15% planning reserve | 50 | 51 | 52 | 54 | 55 | 56 | 57 | 59 | 60 | 61 |
| **Total** | **384** | **393** | **402** | **411** | **421** | **430** | **440** | **450** | **461** | **471** |
| Maritime Electric Capacity Resources: | | | | | | | | | | |
| Charlottetown Thermal Plant | - | - | - | - | - | - | - | - | - | - |
| Borden Plant | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 |
| Combustion Turbine 3 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 |
| Point Lepreau | 29 | 29 | 29 | 29 | 29 | 29 | 29 | 29 | 29 | 29 |
| NB Short-Term Capacity purchases | 225 | 235 | 240 | 250 | 260 | 270 | 280 | 290 | 300 | 310 |
| **Subtotal** A | **363** | **373** | **378** | **388** | **398** | **408** | **418** | **428** | **438** | **448** |
| Purchased Wind Capacity: | | | | | | | | | | |
| Maritime Electric purchased wind nameplate capacity B | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 |
| Effective Load Carrying Capacity ("ELCC") as % of nameplate C | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 |
| ELCC D = B x C | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 |
| **Total E = A + D** | **389** | **399** | **404** | **414** | **424** | **434** | **444** | **454** | **464** | **474** |

IR-6 b to g

**The responses to IR-6b through IR-6g has been filed with the Commission on a confidential basis.**

IR-7 Wind as a capacity resource, referencing "Wind has little capacity value as it cannot be reliably dispatched", (page ii), and wind costs in general, "Maritime Electric intends to procure future on-Island renewable supplies at cost so it can pass any potential savings along to ratepayers" (page 43).

a. Table 15 shows MECL using an ELCC (varying from 23% to 16% as wind penetration increases between 2018 and 2025) to determine a capacity value for wind (estimated as 26 MW total in 2026). Confirm, or explain otherwise, that MECL does count wind as a capacity resource, using the ELCC fraction, when computing overall resource capacity to meet planning reserve requirements.
b. Provide the underlying analysis or basis for MECL's 2018-2025 ELCC percentage trajectory for wind resources as shown in Table 15. If no underlying analysis exists or is available, explain MECL's reasoning for using the ELCC trajectory shown in the table.
c. What is MECL's estimate for the cost and performance of new wind resources for procurement? Please be specific as to scale, timing, performance, and resource location.
d. Indicate if the costs in part c. above are associated with the planned 40 MW farm in 2025 (footnote 24, Table 13, page 29), or other wind farms in general.
e. Provide any further information MECL has on the economic potential for additional utility-scale wind resources for development and related energy and capacity sale to MECL on PEI in addition to the 40 MW wind farm noted above.

***Response:***

a. Yes, Maritime Electric counts wind as a capacity resource, using the effective load carrying capacity ("ELCC") fraction, when computing overall resource capacity to meet planning reserve requirements.

b. **The response to IR-7b has been filed with the Commission on a confidential basis.**

c. Maritime Electric currently has no control over timing or location of future wind energy generation facilities. It connects the facilities as per its Open Access Transmission Tariff obligations, and the generation proponent is responsible to determine the operating characteristics of the wind facility. The Renewable Energy Act currently stipulates the minimum price that Maritime Electric must pay per kilowatt-hour ("kWh") under any new supply agreements with renewable energy generators.

Maritime Electric expects that future wind energy generation facilities will have a higher capacity factor than existing facilities based on advances in turbine technology and facility site design.

The PEI Energy Corporation's ("PEIEC") proposed Eastern Kings Windfarm expansion was originally scheduled to be in service in the fourth quarter of 2020. The project is delayed and a new in-service date has not yet been established. There has been third-party interest in building the 40 MW of new wind generation planned by PEIEC for 2025. While the details of the project are not known, the current assumption is that it will be located in West Prince.

d. The legislated per kWh cost for renewable energy referenced in part c above is associated with the planned 30 MW Eastern Kings Windfarm expansion, the 40 MW windfarm planned for 2025, as well as any other new supply contract with a person or organization that meets the definition of a Renewable Energy Generator in the Renewable Energy Act.

e. At this time, Maritime Electric is not a wind energy developer and, as such, this question would be better addressed by third-party developers or the PEI Energy Corporation.

IR-8 Battery Storage costs, referencing "The cost of energy storage continues to fall as the technology matures but remains uneconomic" (page ii), and "…as such battery storage for grid operations alone is currently uneconomic based on Canadian industry costs" (page 38).

a. Is MECL's conclusion concerning battery storage cost economics based solely on the Alberta battery system noted on page 38?
b. Provide all underlying economic analyses for battery energy storage systems for use on Prince Edward Island conducted by or on behalf of MECL.
c. What are MELC's projected costs for utility-scale battery energy storage systems for installation on PEI? Provide MECL's current estimate for all cost, duration, size, performance and installation timing parameters for utility-scale battery energy storage resources potentially available for installation during the 2022-2025, and 2026-2030 timeframe.
d. What are MELC's projected costs for distributed scale (i.e., installation on the distribution system, either at customer sites behind-the-meter, or in-front-of-meter anywhere on the distribution system including at MECL distribution substations or feeder locations) battery energy storage systems for installation on PEI? Provide MECL's current estimate for all cost, duration, size, performance and installation timing parameters for distributed-scale battery energy storage resources potentially available for installation during the 2022-2025, and 2026-2030 timeframe.
e. What is MECL's specific cost projection for utility-scale solar PV on PEI for the 2022- 2030 time frame?

***Response:***

a. No. The Alberta battery system noted on page 38 of the Integrated System Plan is referenced as a recent Canadian example. Maritime Electric actively participates in a number of industry groups and, in its experience, the general consensus among electric utilities is that battery storage is not yet economic.

b. Maritime Electric has not undertaken its own in-depth economic analysis of utility-scale battery energy storage systems; however, several customers have approached the Company to promote the economics of their proposed battery system projects. While the identity of these customers and their project information cannot be disclosed due to confidentiality obligations, in each case it was determined that battery storage is not yet an economic capacity or ancillary service source on PEI, based on the current cost of available alternatives.

c. Maritime Electric has not developed any detailed cost estimates of utility-scale battery energy storage systems.

d. Maritime Electric has not investigated distribution-level battery storage systems to date. As battery storage is not yet economic on a transmission-scale, Maritime Electric has assumed it is also not yet economic on a distribution-scale.

e. Maritime Electric's cost projection for a utility-scale (10 megawatt) photovoltaic ("PV") solar facility was $18.0 million in 2020. Based on an estimated initial capacity factor of 13 per cent, the levelized cost of energy from such a facility would be 18.27 cents per kWh over a 25 year service life. Maritime Electric has not projected this cost into the future.

IR-9 Customer-side, utility-controlled devices for capacity, referencing “Maritime Electric does not believe that utility control of an array of individual customer devices, with the control devices, communications and security needed to undertake the program, will provide an economic capacity resource at this time”, page ii).

a. Provide all analyses MECL has completed that show the underlying economics of considering use of customer-side, utility-controlled devices “at this time”.
b. If MECL has not completed such analyses, provide any and all information MECL has underlying its belief that these sources will not provide economic capacity.

***Response:***

a. Maritime Electric has not completed an economic analysis of customer-side, utility-controlled devices as a capacity resource.

b. Maritime Electric participated in the PowerShift Atlantic project in 2010 with other Maritime-area utilities that studied development of a virtual power plant using controllable loads. Maritime Electric’s contribution was controlling electric water heaters at a number of customer locations. Through this project, the Company gained insight into the importance of, and challenges associated with, reliable and secure communication connections when controlling customer loads.

The Island load will transform over the next decade as customer conversion to electric space heating and transportation continues to grow. As this growth occurs, new technical solutions will be needed to economically manage and optimize the electricity supply system. One potential solution is utility control of customer-side devices through the use of advanced metering infrastructure (“AMI”) technology. AMI can be used to facilitate a move to time-of-use or other innovative rate structures, with a goal of helping to manage peak load and related infrastructure needs as heating and transportation electrification occurs. An expected benefit of AMI is that the secure information network required for the AMI collector system may provide sufficient communication reliability and security so that utility control of customer-side devices can be effectively implemented.

Maritime Electric is currently preparing a business case for AMI. As AMI could provide the reliable and secure communications that are integral to customer load control, it is prudent that the AMI business case first determine AMI’s feasibility before pursuing other solutions. If a conversion of AMI proceeds, the Company will be in a better position to analyze customer load patterns and customer-side load control programs.

Annual and Hourly Load Information

IR-10 System Hourly Load Data.

a. Provide complete Maritime Electric system hourly (8,760) load data for the three most recent years (e.g., January 2018 to September 2021). If possible, please break these data out by customer class (e.g., residential, commercial, etc.).

If hourly load data does not exist for this entire period, please provide the data for the period for which it is available.

***Response:***

Maritime Electric system hourly load data is included in the Excel spreadsheet IR-10 – Attachment 1.

It is not possible to break out this data by customer class as Maritime Electric does not gather hourly interval data as part of its general meter reading process. Maritime Electric gathered hourly readings for approximately 600 Residential and General Service customers in 2020 and 2021 as part of a Load Study, which was provided in the response to Synapse IR-15 concerning the Company's recent Rate Design Application (UE22503). In addition, the Company receives hourly readings for approximately 15 large customers (whereas Maritime Electric has approximately 80,000 customers in total).

IR-11 If available, please provide the following hourly load/generation (MW) forecast data for 2025 (8,760) for the entire Island, and/or for MECL's own system:

a. Underlying or "base" hourly load;
b. Behind-the-meter solar PV hourly generation;
c. Distributed battery energy storage generation or charging load;
d. Energy efficiency (BAU) load reduction;
e. Demand response load reduction; and
f. Electric vehicle charging load.

If Maritime Electric does not have hourly load forecast data for each category in 2025, please provide the forecast data which is available. If MECL has available a different form of load component aggregation (such as combined solar PV, battery storage impacts), please provide.

***Response:***

a. **The response to IR-11a has been filed with the Commission on a confidential basis.**

b. Maritime Electric has not yet developed an hourly (or other interval-based) behind-the-meter solar PV generation forecast or an aggregation including such data.

c. Maritime Electric has not yet developed an hourly (or other interval-based) distributed battery energy storage generation forecast or an aggregation including such data.

d. Maritime Electric has not yet developed an hourly (or other interval-based) energy efficiency load reduction forecast or an aggregation including such data.

e. Maritime Electric has not yet developed an hourly (or other interval-based) demand response load reduction forecast or an aggregation including such data.

f. Maritime Electric has not yet developed an hourly (or other interval-based) electric vehicle charging load forecast or an aggregation including such data.

IR-12 Please provide Maritime Electric annual customer sales forecast (GWh) from 2020-2040 for each of the following items:

a. Underlying or "base" load;
b. Behind-the-meter solar PV hourly generation;
c. Distributed battery energy storage generation;
d. Energy efficiency (BAU) load reduction;
e. Demand response load reduction; and
f. Electric vehicle charging load.

If Maritime Electric does not have this data out to 2040 (e.g., ends at 2030), please provide the compound annual growth rate (CAGR) that can be used to extrapolate the electricity sales forecast out to 2040.

Note: Can combine battery storage and solar PV together into a category called distributed energy resources (DER) if a separate hourly breakout for Solar PV and battery storage is unavailable.

***Response:***

This response is based on Maritime Electric's latest sales forecast, which was developed in February 2021.

The effects of behind-the-meter solar photovoltaic ("PV") and distributed battery energy storage generation (part b and c of this interrogatory, respectively) has not been broken out and is therefore reported as not available ("N/A"); however, based on the growing popularity of solar PV, particularly for Residential customers, solar PV will be included in the Company's sales forecasts in the near future.

The energy efficiency and demand response load reduction measures (part d and e of this interrogatory, respectively) have been grouped together under Demand-Side Management.

The responses to IR-12 a to f are provided in Table 1. All values shown are in gigawatt hours ("GWh").

**Table 1**
**Breakdown of Maritime Electric Annual Sales Forecast 2021 to 2030 (GWh)**

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| **a -** Base Load | 1,348.9 | 1,394.9 | 1,426.5 | 1,455.8 | 1,486.0 | 1,516.1 | 1,546.1 | 1,575.5 | 1,604.0 | 1,631.0 |
| **b and c -** Solar and Battery | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **d and e –** Demand-Side Management[a] | (13.3) | (21.8) | (30.4) | (38.9) | (47.5) | (56.0) | (64.6) | (73.1) | (81.7) | (90.2) |
| **f -** Electric Vehicles | 1.2 | 2.4 | 3.6 | 6.0 | 9.0 | 12.0 | 16.5 | 21.0 | 25.5 | 30.0 |
| **Energy** | 1,336.8 | 1,375.5 | 1,399.7 | 1,422.9 | 1,447.5 | 1,472.1 | 1,498.0 | 1,523.3 | 1,547.9 | 1,570.8 |

a. Maritime Electric assumed that the projected gains in the last year of efficiencyPEI's current Electric Efficiency and Conservation Plan will continue to 2030.

Maritime Electric's sales forecast does not extend beyond 2030. The annual average total energy sales growth for 2021 to 2030 is forecast to be 2.0 per cent. A 2.0 per cent compound annual growth rate is also reasonable for the years 2031 to 2040.

IR-13 Please provide the Maritime Electric annual peak load forecast (MW) from 2020-2040 for each of the following items:

a. Underlying or "base" load;
b. Behind-the-meter solar PV hourly generation;
c. Distributed battery energy storage generation;
d. Energy efficiency (BAU) load reduction;
e. Demand response load reduction; and
f. Electric vehicle charging load.

If Maritime Electric does not have this data out to 2040 (e.g., ends at 2030), please provide the compound annual growth rate (CAGR) that can be used to extrapolate the electricity sales forecast out to 2040.

Note: Can combine battery storage and solar PV together into a category called distributed energy resources (DER) if a separate hourly breakout for Solar PV and battery storage is unavailable.

***Response:***

This response is based on Maritime Electric's latest load forecast, which was developed in February 2021.

The effects of behind-the-meter solar photovoltaic ("PV") and distributed battery energy storage generation (part b and c of this interrogatory, respectively) has not been broken out and is therefore reported as not available ("N/A"). Behind the meter solar PV generation output is zero during system peaks in the winter months, so until a significant number of solar PV installations have battery backup, there is no benefit to including them in the peak load forecast.

The energy efficiency and demand response load reduction measures (part d and e of this interrogatory, respectively) have been grouped together under Demand-Side Management.

The responses to IR-13 a to f are provided in Table 1. All values shown are in megawatts ("MW").

**Table 1**
**Breakdown of Maritime Electric Load Forecast 2021 to 2030 (MW)**

| | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|---|---|---|---|---|---|
| **a -** Base Load | 274.9 | 284.7 | 292.8 | 300.5 | 308.3 | 316.2 | 324.0 | 331.6 | 339.1 | 344.5 |
| **b and c -** Solar and Battery | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **d and e –** Demand-Side Management[a] | (3) | (4.4) | (6.4) | (8.1) | (9.9) | (11.6) | (13.3) | (15.0) | (16.7) | (18.4) |
| **f -** Electric Vehicles | 0.2 | 0.4 | 0.7 | 1.1 | 1.7 | 2.2 | 3.1 | 3.9 | 4.8 | 5.6 |
| **Peak Load** | 272.1 | 280.4 | 287.0 | 293.4 | 300.1 | 306.8 | 313.8 | 320.5 | 327.1 | 331.7 |

a. Maritime Electric assumed that the projected gains in the last year of efficiencyPEI's current Electric Efficiency and Conservation Plan will continue to 2030.

Maritime Electric's load forecast does not extend beyond 2030. The annual average peak load growth for 2021 to 2030 is forecast to be 2.2 per cent. A 2.2 per cent compound annual growth rate is also reasonable for the years 2031 to 2040.

Fuel Price Forecasts

IR-14 Fuel costs.

a. Please provide the latest annual delivered fuel price forecasts for MECL dispatchable peaking generation resources between 2021 – 2040 (excluding Charlottetown steam unit). Please indicate the units for the fuel price forecasts.

b. If the entire period is not available, please provide data for the years that are available and an appropriate growth rate to extrapolate the data out from the last year for which data is available.

Note: Preference is to receive the fuel prices in USD per barrel. However, these prices can be provided in USD per MMBtu along with the corresponding heat rates for each of the fuel options (e.g., diesel, HFO) in MMBtu/bbl.

***Response:***

a. Maritime Electric has used the United States Energy Information Administration ("USEIA") Short-Term Energy Outlook, October 2020, to produce a delivered diesel fuel price forecast for its dispatchable standby generation resources for the years 2021 to 2040. The forecast is provided in the Excel spreadsheet IR-14 – Attachment 1, 'IR-14 Summary' worksheet. The referenced USEIA Short-Term Energy Outlook October 2020 data is provided in the 'IR-14 Raw Data' worksheet of the IR-14 – Attachment 1 spreadsheet.

b. Data for the entire period is provided in the response to IR-14a.

Energy Resource Information

IR-15 For every planned, on-island unit coming online between 2021 and 2040 please indicate the following:

a. Resource type (e.g., wind);
b. Capacity (MW);
c. Storage capacity (MW/MWh), if applicable;
d. Capacity factor (%);
e. Capacity credit used for capacity planning purposes;
f. If the project is through a power purchases agreement (PPA);
g. Planned commission date;
h. Planned retirement date;
i. Fixed cost for each planned unit in $/kW-yr;
j Variable O&M for each planned unit on a $/MWh basis;
k. Forecasted capital cost expenditure for each planned unit on a $/kW basis.; and
l. Any recurring capital expenditure on an annual basis between 2020 and 2040.

Note: Please indicate whether the dollar values are nominal or real dollars and whether they are USD or CAD.

***Response:***

The responses to IR-15 a to l are shown in Table 1.

To address concerns around future security of supply, the Company plans to engage a consultant in 2022 to undertake an in-depth analysis of the regional capacity market and future capacity prospects, as well as determine the optimal size, location and timing for additional on-Island generating capacity, if required. This “On-Island Generating Capacity Study” is described on pages 46 to 48 of the 2022 Capital Budget Application.

With the timing of the proposed study being 2022, details for any new additional on-Island generating capacity (i.e., resource type, capacity, storage capacity, capacity factor, capacity credit used for capacity planning purposes, planned commissioning date, etc.) proposed by Maritime Electric will not be known until after this study is complete. For this reason, information shown in Table 1 for combustion turbine CT4 and CT5 projects is indicative of what was contemplated when the 2020 Integrated System Plan was developed. The balance of the information shown in Table 1 reflects projects that are planned by the PEI Energy Corporation.

| **Table 1**<br>**On-Island Generation Projects Planned for 2021 to 2040** | | | | | | |
|---|---|---|---|---|---|---|
| | | **Slemon Park Solar** | **Eastern Kings Windfarm** | **Western Windfarm** | **Combustion Turbine CT4** | **Combustion Turbine CT5[a]** |
| a | Resource type | Solar | Wind | Wind | Diesel | Diesel |
| b | Capacity (MW) | 10 | 30 | 40 | 60 | 80 |
| c | Storage capacity (MW/MWh) | 0.5/1.0 | - | Unknown | - | - |
| d | Capacity factor (%)[b] | 14 | 40 | 40 | - | - |
| e | Capacity credit | - | - | - | 60 | 80 |
| f | Power purchase agreement ("PPA")[c] | Yes | Yes | Yes | N/A | N/A |
| g | Commission date | Q4 2022 | Unknown | 2025 | 2026 | 2030 |
| h | Retirement date[d] | 2047 | Unknown | 2050 | 2076 | 2080 |
| i | Fixed costs ($/kW-yr) | Responsibility of owner, PEI Energy Corporation | | | Detailed study of these costs has not yet been undertaken | |
| j | Variable O&M ($/MWh) | | | | | |
| k | Capital expenditure ($/kW) | | | | | |
| l | Recurring capital ($/yr) | | | | | |

a. Replacement when existing Borden combustion turbines CT1 (1971) and CT2 (1973) reach end of life.
b. Combustion turbines are used primarily for backup and emergency supply purposes, and therefore have no designated capacity factor.
c. 'Yes' indicates that a PPA is in place; 'N/A' indicates that a PPA is not required.
d. Retirement dates assumed based on 25 year life (solar, wind) and 50 year life (combustion turbines).

IR-16 For each existing unit or import (e.g., thermal, solar, wind, NB purchase) on MECL's system please provide the following data for the historical years 2018, 2019, and 2020:

a. Hourly Generation in MWh on an 8760 basis for each year. If hourly generation is not available, please provide annual generation.

***Response:***

a. **The response to IR-16a has been filed with the Commission on a confidential basis.**

IR-17 For each existing unit (e.g., thermal, solar, wind) on MECL's system in 2020 please provide the following:

a. Fixed cost in $/kW-yr on an annual basis starting in 2020 through 2040;
b. Variable O&M in $/MWh on an annual basis starting in 2020 through 2040;
c. Installation date;
d. Expected retirement date;
e. Any recurring capital expenditure on an annual basis between 2020 and 2040;
f. Whether the unit is dispatched economically or is a "must run" unit required to commit a minimum amount of generation; and
g. Whether the unit is RPS eligible and the % of generation that is RPS eligible.

Note: Please indicate whether the dollar values are nominal or real dollars. We presume all units are $CAD, but confirm or indicate otherwise.

***Response:***

a. A total of 92.5 megawatts ("MW") of wind energy (in 2020) was purchased from the PEI Energy Corporation ("PEIEC") under various Power Purchase Agreements. As Maritime Electric does not own, operate or maintain the wind farms that produced this energy, it does not have access to the requested data concerning the PEIEC's existing wind facilities. There were no utility-scale solar facilities under contract with Maritime Electric in 2020.

Maritime Electric also does not have base-loaded, dispatchable generation. Maritime Electric's generating fleet of three combustion turbines and two steam turbines (until retired on December 31, 2021) are standby units only, mainly used in curtailment and emergency energy situations. To illustrate this, the operating hours for each of the Company's three combustion turbines and two steam turbines for the last five years are shown in Table 1. Maritime Electric's generating unit with the highest use (Combustion Turbine 3) averaged 107.8 operating hours per year (out of a possible 8,760 hours) over the last five years. While Maritime Electric's combustion and steam turbines have low operating hours, they are a valuable on-Island capacity resource and are important for security of supply.

**Table 1**
**Operating Hours for Maritime Electric's Standby Generation Fleet 2016 to 2020**

| | Combustion Turbine 1 | Combustion Turbine 2 | Combustion Turbine 3 | Steam Turbine 9 | Steam Turbine 10 |
|---|---|---|---|---|---|
| 2016 | 10.3 | 46.9 | 176.5 | 93.0 | 77.0 |
| 2017 | 15.1 | 49.5 | 178.5 | 131.0 | 72.0 |
| 2018 | 16.8 | 38.4 | 115.1 | - | - |
| 2019 | 16.4 | 20.2 | 36.0 | - | - |
| 2020 | 12.8 | 13.2 | 32.9 | - | - |
| **Average** | **14.3** | **33.6** | **107.8** | **44.8** | **29.8** |

The annual operating hours on these units are often low enough that the annual station service consumption in megawatt-hours ("MWh") at the Company's generation facilities exceeds the annual gross production, such that the net production in MWh is a negative value. Given that Maritime Electric's generating facilities operate so infrequently, it becomes problematic to compare these units to peaking plants (or base-loaded plants) using costs per unit of generation produced.

The responses to IR-17 a to g for existing Maritime Electric owned on-Island generation equipment are provided in Table 1.

**Table 1**
**Existing Maritime Electric Owned On-Island Generating Equipment**

| | Combustion Turbine 1 ("CT1") | Combustion Turbine 2 ("CT2") | Combustion Turbine 3 ("CT3") | Steam Plant Unit 9 | Steam Plant Unit 10 |
|---|---|---|---|---|---|
| Resource type | Thermal | Thermal | Thermal | Thermal | Thermal |
| Fuel type | Diesel | Diesel | Diesel | Bunker C | Bunker C |
| Capacity (MW) | 15 | 25 | 49 | 20 | 20 |
| **a.** Fixed costs ($/kW-yr)[a,b] | 41 | see CT1 | 64 | 236 | see Unit 9 |
| **b.** Variable O&M ($/MWh)[a,b] | 892 | see CT1 | 284 | N/A | see Unit 9 |
| **c.** Commission date | 1971 | 1973 | 2005 | 1963 | 1968 |
| **d.** Expected retirement date[d] | 2031 | 2033 | 2055 | 2021 | 2021 |
| **e.** Recurring capital ($/yr)[e] | 150,000 | 150,000 | 175,000 | N/A | N/A |
| **f.** Dispatched economically or "must run" unit[f] | Both | Both | Both | N/A | N/A |
| **g.** RPS eligible | No | No | No | No | No |

a. Amounts shown in the table are based on 2020 Actuals and are in Canadian dollars. Forecast costs for 2021 to 2026 are provided in the Excel spreadsheet IR-17 – Attachment 1 (see 'IR-17 BGS' worksheet for CT1 and CT2, 'IR-17 CT3' worksheet for CT3, and 'IR-17 CSP' worksheet for Steam Plant Units 9 and 10). Forecast costs for 2026 to 2040 are projected to increase at 2 per cent annually for all existing generating equipment.
b. CT1 and CT2 fixed and variable costs are not tracked separately and therefore the amount shown for CT1 is the total for both units. The same also applies for Steam Plant Units 9 and 10. All variable operating and maintenance ("O&M") costs are in Canadian dollars.
c. No energy was generated by the Steam Plant Units 9 and 10 in 2020.
d. The retirement date for Steam Plant Units 9 and 10 is December 31, 2021. Retirement dates for CT1 and CT2, which have already reached 50 years, has been extended by 10 years based on their low operating hours and good condition.
e. Amounts shown are approximate based on recurring projects at the Charlottetown Generating Station (Capital Budget Sections 4.1 and 4.2) and the Borden Generating Station (Capital Budget Sections 4.3 and 4.4) in the 2022 Capital Budget Application. The Borden recurring projects total of $300,000/year was split evenly between the two units. The amounts shown in the table are forecast to increase by 2 per cent annually to 2040. All recurring capital cost amounts are in Canadian dollars.
f. The combustion turbines can be economically dispatched; however, they are primarily operated for backup and emergency purposes and therefore characterized as "must run" the majority of time.

Ancillary Service Information

IR-18 Please provide the following Maritime Electric system information:

a. Planning reserve margins
b. MECL's estimate or assumptions for the cost of unserved energy, in the event of loss of firm load.

***Response:***

a. Maritime Electric capacity planning, as required by the NB Power – System Operator ("NBP-SO"), involves forecasting peak load, subtracting interruptible load and adding a 15 per cent planning reserve. This approach, which is based upon Northeast Power Coordinating Council ("NPCC") reliability criteria and good utility practice, ensures sufficient margin in the Maritimes area to accommodate the loss of the single largest generating unit (i.e., Point Lepreau Nuclear Generating Station at 705 MW gross), and still supply all customer load, with the exception of one event in a ten-year period. Planning reserve margins also provide the ability to accommodate minor customer load variations. As already noted in the response to IR-17a, Maritime Electric counts wind as a capacity resource, using the effective load carrying capacity ("ELCC") fraction, when calculating the overall resource capacity available to meet planning reserve requirements.

b. In the event of the loss of firm load, Maritime Electric encounters the cost of unserved energy only for those services which are based on capacity. Services based on energy are un-procured and, therefore, Maritime Electric does not incur the associated costs. The existing Energy Purchase Agreement ("EPA") with New Brunswick Energy Marketing requires a minimum of two years notice to change reserved capacity quantities.

Table 1 details the Ancillary Services that Maritime Electric procures from both New Brunswick and Prince Edward Island systems, and those services for which Maritime Electric incurs a cost for unserved energy.

| Table 1<br>Summary of Maritime Electric Ancillary Services Procurement | | | |
|---|---|---|---|
| **Open Access Transmission Tariff ("OATT") Schedule** | **NB System OATT** | **PEI System OATT** | **Cost for Unserved Energy** |
| Schedule 1 – Scheduling, System Control and Dispatch | Included in bundled energy price through EPA | Charged per MWh | No |
| Schedule 2 – Reactive Supply and Voltage Control | Included in bundled energy price through EPA | Charged per MWh | No |
| Schedule 3 – Regulation and Frequency Response | Included in bundled energy price through EPA | Charged per MWh | No |
| Schedule 4 – Energy Imbalance | Charged per MWh | Charged per MWh | Yes/No[a] |
| Schedule 5 – Spinning Reserve | Included in bundled energy price through EPA | Procured from NB | No |
| Schedule 6 – Non-Spinning Reserve | Supplied by Borden CT's or purchased from NBP-SO when required | Mixture of NB and PEI Assets | No, typically self-supplied, but when required purchased at the applicable NBP-SO OATT rate |
| Schedule 7 – Long Term Firm Point to Point[b] | Included in bundled energy price through EPA | - | No |
| Schedule 8 – Non-Firm Point to Point[b] | Included in bundled energy price through EPA | - | No |
| Schedule 9 – Non-Capital Support Charge[b] | Cost based on capital cost and overheads | - | No |
| Schedule 10 – Residual Uplift | Based on system usage | Based on system usage | No |
| Attachment H – Network Integration Transmission Service | Included in bundled energy price | Charged per MW, based on system usage | No |

a. Imbalances (or Inadvertent Energy) caused by a loss of Firm Load could result in either a credit or debit associated with the energy when sold back to the NBP-SO at the Final Hourly Marginal Cost.
b. Maritime Electric does not take Schedule 7, Schedule 8 and Schedule 9 services on PEI.

IR-19 Please provide the following ancillary service information:

a. Historical regulation up/down requirements for MECL's system for 2020;
b. Forecasted regulation up/down requirements for MECL's system for years 2021-2040. If data does not exist for the entire period, please provide data for the period for which it is available;
c. A description of how the regulation up/down requirements are derived/established. If these values are derived formulaically, provide any relevant worksheets with formulae intact; and
d. Variation in requirements due to seasonality or other expected differences in the pattern of regulation up/down requirements across the year.

Note: If data does not exist for the entire period, please provide data for the period for which it is available.

***Response:***

a. Maritime Electric does not have base-loaded, dispatchable generation in its fleet. Regulation is therefore provided by NB Power's generating units and is included in the bundled energy pricing (Firm, Secure and Assured Energy products) within the Energy Purchase Agreement ("EPA") until December 31, 2026. As Maritime Electric does not provide Regulation, it does not monitor the up/down requirements.

b. If Regulation is not included in future EPA pricing, upon the expiration of the current EPA on December 31, 2026, Maritime Electric would purchase the Regulation from the NB Power - System Operator as it is required to provide Regulation under the current NB Power Open Access Transmission Tariff.

c. Please refer to responses to IR-19a and b.

d. Please refer to responses to IR-19a and b.

IR-20 Please provide the following information:

a. Historical operating reserve (e.g., spinning reserve) requirements for MECL's system for 2020.
b. Forecasted operating reserve requirements for MECL's system for years 2021-2040. If data does not exist for the entire period, please provide data for the period for which it is available.
c. Please provide a description of how the operating reserve requirements are derived/established. If these values are derived formulaically, provide any relevant worksheets with formulae intact.
d. In reference to operating reserves, please provide variation in requirements due to seasonality or other expected differences in the pattern of operating reserve across the year.

***Response:***

a. Spinning Reserve requirements for Maritime Electric are provided by NB Power's generation fleet and the costs of Spinning Reserve are included in the bundled energy pricing (Firm, Secure and Assured Energy products) within the Energy Purchase Agreement ("EPA") with NB Energy Marketing. The Company's historical operating reserve requirements for 2020 are provided in IR-20 – Attachment 1.

b. Maritime Electric's operating reserve requirements for 2021 year to date and a forecast for the months of November and December 2021 are provided in IR-20 – Attachment 2. It is difficult to forecast Maritime Electric's operating reserve requirements within the regional supply system as the Company's obligation is set by the NB Power – System Operator ("NBP-SO"), as described in the response to IR-20c. Historical operating reserve requirement data for the past ten years indicates a trend of Maritime Electric's obligation percentage increasing annually; however, this is likely a reflection of the significant shift to electric-based space heating by the Company's customers starting around 2015, relative to other utilities in the region.

The operating reserve requirements for Maritime Electric from 2011 to 2021 are provided in Table 1.

| Table 1<br>Operating Revenue Obligation Percentage 2011 to 2021 | | |
|---|---|---|
| **Begin Date** | **End Date** | **Obligation Percentage (%)** |
| 01-February-11 | 31-January-12 | 6.89 |
| 01-February-12 | 31-January-13 | 6.78 |
| 01-February-13 | 31-January-14 | 6.90 |
| 01-February-14 | 31-January-15 | 6.90/7.13[a] |
| 01-February-15 | 31-January-16 | 7.31/7.58[b] |
| 01-February-16 | 31-January-17 | 7.69 |
| 01-February-17 | 31-January-18 | 7.97 |
| 01-February-18 | 31-January-19 | 8.11 |
| 01-February-19 | 31-January-20 | 7.96 |
| 01-February-20 | 31-January-21 | 8.37 |
| 01-February-21 | 31-January-22 | 9.21 |

a. February was at the previous year obligation percentage of 6.90 per cent and increased to 7.13 per cent, which occurred on March 1 because the NBP-SO was late sending out updated obligation.

b. January to July was 7.31 per cent and August to December increased to 7.58 per cent when the Updated NB Open Access Transmission Tariff was approved. The underlying calculation changed from using Maritime Electric's Non-Coincident Peak to using its Coincident Peak to determine the percentage obligation.

c. In January of each year, the NBP-SO sends Maritime Electric the monthly peaks for the previous year and requests the Company's Coincident Peak load amount (NBP-SO also does the same for other customers within the control area). Maritime Electric's Coincident Peak load information for 2020 is shown in Table 2.

**Table 2**
**Maritime Electric Peak Loads Coincident with the New Brunswick Peak 2020**

| Month | Peak Hour UTC | Peak Hour NB HR Bgn | Peak Hour NB HR End | PEI Coincident Peak Load (MW) |
|---|---|---|---|---|
| January | 01/21/2020 12:00 | 01/21/2020 8:00 | 01/21/2020 9:00 | 267 |
| February | 02/21/2020 11:00 | 02/21/2020 7:00 | 02/21/2020 8:00 | 275 |
| March | 03/23/2020 11:00 | 03/23/2020 8:00 | 03/23/2020 9:00 | 224 |
| April | 04/01/2020 12:00 | 04/01/2020 9:00 | 04/01/2020 10:00 | 195 |
| May | 05/09/2020 14:00 | 05/09/2020 11:00 | 05/09/2020 12:00 | 191 |
| June | 06/02/2020 11:00 | 06/02/2020 8:00 | 06/02/2020 9:00 | 166 |
| July | 07/28/2020 19:00 | 07/28/2020 16:00 | 07/28/2020 17:00 | 210 |
| August | 08/11/2020 19:00 | 08/11/2020 16:00 | 08/11/2020 17:00 | 216 |
| September | 09/21/2020 11:00 | 09/21/2020 8:00 | 09/21/2020 9:00 | 181 |
| October | 10/28/2020 11:00 | 10/28/2020 8:00 | 10/28/2020 9:00 | 208 |
| November | 11/25/2020 14:00 | 11/25/2020 10:00 | 11/25/2020 11:00 | 232 |
| December | 12/17/2020 12:00 | 12/17/2020 8:00 | 12/17/2020 9:00 | 252 |

With Maritime Electric's Coincident Peak load information, the NBP-SO calculates the Company's percentage obligation for the next 12-month period and provides the Ancillary Service and new obligation requirements, which Maritime Electric must then either self-supply or purchase through the NBP-SO (or via a third party that must be approved by the NBP-SO). At the end of each month, if Maritime Electric does not self-supply, it is invoiced by NBP-SO based on the services rendered.

d. Operating reserve requirements do not vary significantly over the course of a year. A significant change to the operating reserve requirements might occur when, for example, the Point Lepreau Nuclear Generating Station undergoes a planned or unplanned outage, and the second largest generator on NB Power's system (typically Belledune Generating Station) is used in the operating reserve requirements calculations. Such an event would be considered an exception as it is not a normal occurrence.

# I N T E R R O G A T O R I E S

## IR-20 – Attachment 1 and 2

IR-20a

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **January-20** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 7.96% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.5 | 1.5 | Mactquac |
| Load Following | 53 | 4.2 | 4.2 | Mactquac |
| Spinning Reserve | 87.5 | 7 | 7 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 222.5 | 17.7 | | Purchased from the NB Poiwer System Operator |
| Supplemental Reserve - 30 minute | 183.0 | 14.6 | | Purchased from the NB Poiwer System Operator |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **February-20** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 8.37% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.6 | 1.6 | Mactquac |
| Load Following | 53 | 4.4 | 4.4 | Mactquac |
| Spinning Reserve | 87.5 | 7.3 | 7.3 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 222.5 | 18.6 | | Purchased from the NB Poiwer System Operator |
| Supplemental Reserve - 30 minute | 183.0 | 15.3 | | Purchased from the NB Poiwer System Operator |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **March-20** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 8.37% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.6 | 1.6 | Mactquac |
| Load Following | 53 | 4.4 | 4.4 | Mactquac |
| Spinning Reserve | 87.5 | 7.3 | 7.3 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 222.5 | 18.6 | | Purchased from the NB Poiwer System Operator |
| Supplemental Reserve - 30 minute | 183.0 | 15.3 | | Purchased from the NB Poiwer System Operator |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **April-20** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 8.37% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.6 | 1.6 | Mactquac |
| Load Following | 53 | 4.4 | 4.4 | Mactquac |
| Spinning Reserve | 87.5 | 7.3 | 7.3 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 222.5 | 18.6 | 18.6 | MECL Combustion Turbines |
| Supplemental Reserve - 30 minute | 183.0 | 15.3 | 15.3 | MECL Combustion Turbines |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **May-20** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 8.37% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.6 | 1.6 | Mactquac |
| Load Following | 53 | 4.4 | 4.4 | Mactquac |
| Spinning Reserve | 87.5 | 7.3 | 7.3 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 222.5 | 18.6 | 18.6 | MECL Combustion Turbines |
| Supplemental Reserve - 30 minute | 183.0 | 9.4 | 9.4 | MECL Combustion Turbines |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **June-20** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 8.37% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.6 | 1.6 | Mactquac |
| Load Following | 53 | 4.4 | 4.4 | Mactquac |
| Spinning Reserve | 87.5 | 7.3 | 7.3 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 222.5 | 18.6 | 18.6 | MECL Combustion Turbines |
| Supplemental Reserve - 30 minute | 183.0 | 9.4 | 9.4 | MECL Combustion Turbines |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **July-20** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 8.37% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.6 | 1.6 | Mactquac |
| Load Following | 53 | 4.4 | 4.4 | Mactquac |
| Spinning Reserve | 87.5 | 7.3 | 7.3 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 222.5 | 18.6 | 18.6 | MECL Combustion Turbines |
| Supplemental Reserve - 30 minute | 183.0 | 9.4 | 9.4 | MECL Combustion Turbines |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **August-20** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 8.37% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.6 | 1.6 | Mactquac |
| Load Following | 53 | 4.4 | 4.4 | Mactquac |
| Spinning Reserve | 87.5 | 7.3 | 7.3 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 222.5 | 18.6 | 18.6 | Mactquac |
| Supplemental Reserve - 30 minute | 183.0 | 9.4 | 9.4 | Mactquac |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **September-20** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 8.37% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.6 | 1.6 | Mactquac |
| Load Following | 53 | 4.4 | 4.4 | Mactquac |
| Spinning Reserve | 66.5 | 5.6 | 5.6 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 180.5 | 15.1 | 15.1 | Mactquac |
| Supplemental Reserve - 30 minute | 112.0 | 9.4 | 9.4 | Mactquac |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **October-20** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 8.37% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.6 | 1.6 | Mactquac |
| Load Following | 53 | 4.4 | 4.4 | Mactquac |
| Spinning Reserve | 66.5 | 5.6 | 5.6 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 180.5 | 15.1 | 15.1 | MECL Combustion Turbines |
| Supplemental Reserve - 30 minute | 112.0 | 9.4 | 9.4 | Mactquac |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **November-20** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 8.37% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.6 | 1.6 | Mactquac |
| Load Following | 53 | 4.4 | 4.4 | Mactquac |
| Spinning Reserve | 87.5 | 7.3 | 7.3 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 222.5 | 18.6 | | Purchased from the NB Poiwer System Operator |
| Supplemental Reserve - 30 minute | 183.0 | 15.3 | | Purchased from the NB Poiwer System Operator |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **December-20** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 8.37% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.6 | 1.6 | Mactquac |
| Load Following | 53 | 4.4 | 4.4 | Mactquac |
| Spinning Reserve | 87.5 | 7.3 | 7.3 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 222.5 | 18.6 | | Purchased from the NB Poiwer System Operator |
| Supplemental Reserve - 30 minute | 183.0 | 15.3 | | Purchased from the NB Poiwer System Operator |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

IR-20b

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **January-21** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 8.37% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.6 | 1.6 | Mactquac |
| Load Following | 53 | 4.4 | 4.4 | Mactquac |
| Spinning Reserve | 87.5 | 7.3 | 7.3 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 222.5 | 18.6 | | Purchased from the NB Poiwer System Operator |
| Supplemental Reserve - 30 minute | 183.0 | 15.3 | | Purchased from the NB Poiwer System Operator |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **February-21** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 9.21% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.7 | 1.7 | Mactquac |
| Load Following | 53 | 4.9 | 4.9 | Mactquac |
| Spinning Reserve | 87.5 | 8.1 | 8.1 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 222.5 | 20.5 | | Purchased from the NB Poiwer System Operator |
| Supplemental Reserve - 30 minute | 183.0 | 16.9 | | Purchased from the NB Poiwer System Operator |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **March-21** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 9.21% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.7 | 1.7 | Mactquac |
| Load Following | 53 | 4.9 | 4.9 | Mactquac |
| Spinning Reserve | 87.5 | 8.1 | 8.1 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 222.5 | 20.5 | | Purchased from the NB Poiwer System Operator |
| Supplemental Reserve - 30 minute | 183.0 | 16.9 | | Purchased from the NB Poiwer System Operator |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **April-21** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 9.21% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.7 | 1.7 | Mactquac |
| Load Following | 53 | 4.9 | 4.9 | Mactquac |
| Spinning Reserve | 87.5 | 8.1 | 8.1 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 222.5 | 20.5 | 20.5 | MECL Combustion Turbines |
| Supplemental Reserve - 30 minute | 183.0 | 16.9 | 16.9 | MECL Combustion Turbines |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **May-21** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 9.21% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.7 | 1.7 | Mactquac |
| Load Following | 53 | 4.9 | 4.9 | Mactquac |
| Spinning Reserve | 87.5 | 8.1 | 8.1 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 243.5 | 22.4 | 20.5 | MECL Combustion Turbines |
| Supplemental Reserve - 30 minute | 112.0 | 10.3 | 16.9 | MECL Combustion Turbines |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **June-21** | | | **June 1-6 & June 19-30** |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 9.21% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.7 | 1.7 | Mactquac |
| Load Following | 53 | 4.9 | 4.9 | Mactquac |
| Spinning Reserve | 87.5 | 8.1 | 8.1 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 243.5 | 22.4 | 22.4 | MECL Combustion Turbines |
| Supplemental Reserve - 30 minute | 112.0 | 10.3 | 10.3 | MECL Combustion Turbines |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **July-21** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 9.21% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.7 | 1.7 | Mactquac |
| Load Following | 53 | 4.9 | 4.9 | Mactquac |
| Spinning Reserve | 87.5 | 8.1 | 8.1 | Mactquac |
| Supplemental Reserve - 10 minute | 243.5 | 22.4 | 22.4 | MECL Combustion Turbines |
| Supplemental Reserve - 30 minute | 112.0 | 10.3 | 10.3 | MECL Combustion Turbines |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **August-21** | | | **August 1-23** |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 9.21% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.7 | 1.7 | Mactaquac |
| Load Following | 53 | 4.9 | 4.9 | Mactaquac |
| Spinning Reserve | 87.5 | 8.1 | 8.1 | Mactaquac |
| Supplemental Reserve - 10 minute | 222.5 | 20.5 | 20.5 | MECL Combustion Turbines |
| Supplemental Reserve - 30 minute | 112.0 | 10.3 | 10.3 | MECL Combustion Turbines |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **August-21** | | | **August 24-31** |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 9.21% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.7 | 1.7 | Mactaquac |
| Load Following | 53 | 4.9 | 4.9 | Mactaquac |
| Spinning Reserve | 87.5 | 8.1 | 8.1 | Mactaquac |
| Supplemental Reserve - 10 minute | 237.5 | 21.9 | 21.9 | MECL Combustion Turbines |
| Supplemental Reserve - 30 minute | 112.0 | 10.3 | 10.3 | MECL Combustion Turbines |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **September-21** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 9.21% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.7 | 1.7 | Mactaquac |
| Load Following | 53 | 4.9 | 4.9 | Mactaquac |
| Spinning Reserve | 87.5 | 8.1 | 8.1 | Mactaquac |
| Supplemental Reserve - 10 minute | 222.5 | 20.5 | 20.5 | MECL Combustion Turbines |
| Supplemental Reserve - 30 minute | 183.0 | 16.9 | 16.9 | MECL Combustion Turbines |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **October-21** | | | |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 9.21% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.7 | 1.7 | Mactaquac |
| Load Following | 53 | 4.9 | 4.9 | Mactaquac |
| Spinning Reserve | 87.5 | 8.1 | 8.1 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 222.5 | 20.5 | 20.5 | MECL Combustion Turbines |
| Supplemental Reserve - 30 minute | 183.0 | 16.9 | 16.9 | MECL Combustion Turbines |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **November-21** | | | **Forecasted** |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 9.21% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.7 | 1.7 | Mactaquac |
| Load Following | 53 | 4.9 | 4.9 | Mactaquac |
| Spinning Reserve | 87.5 | 8.1 | 8.1 | Interruptable Load Reserve |
| Supplemental Reserve - 10 minute | 222.5 | 20.5 | 20.5 | MECL Combustion Turbines |
| Supplemental Reserve - 30 minute | 183.0 | 16.9 | 16.9 | MECL Combustion Turbines |

**Notes:**

**1. Market Participants are required to identify the name of the Registered Facility when self-supply.**

| | | | | |
|---|---|---|---|---|
| Customer Company: | MECL | | | |
| Customer Contact: | John MacLeod | | | |
| | Kent Nicholson | | | |
| | Jim Coyle | | | |
| **Month** | **December-21** | | | **Forecasted** |
| Transmission Service Customer Type | Point-to-Point | | | |
| Percentage Obligation | 9.21% | | | |
| | | | | |
| | **Forecast for the month** | | | |
| | NBSO Balancing Area Requirement (MW) | Customer Requirement (MW) | Customer Self-Supply | Source of supply |
| Regulation | 19 | 1.7 | 1.7 | Mactaquac |
| Load Following | 53 | 4.9 | 4.9 | Mactaquac |
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