**MARITIME ELECTRIC**
A FORTIS COMPANY

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February 18, 2016

Mr. Mark Lanigan
Regulatory Services
Island Regulatory and Appeals Commission
PO Box 577
501–134 Kent Street
Charlottetown PE C1A 7L1

Dear Mr. Lanigan:

**General Rate Agreement Filing Docket UE20942**
**Response to Interrogatories from Commission Staff**

Please find attached the Company's response to the Interrogatories filed by Commission Staff with respect to the General Rate Agreement filing. An electronic copy will follow shortly.

Yours truly,

MARITIME ELECTRIC

Jason C. Roberts
Director, Regulatory & Financial Planning

JCR04
Enclosure

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## GENERAL

1. **Provide a breakdown, by category, of all payments to Fortis or Fortis related companies for years 2014 and 2015.**

1. **Response:**

The following schedule is breakdown of all payments to Fortis Inc. and related companies for the past two years:

| Schedule of Payments to Fortis Inc. and Fortis Related Companies | | | |
|---|---|---|---|
| **Payee** | **Description** | **2014 Actual** | **2015 Actual** |
| FortisWest Inc. | Dividends(1) | $ 8,000,000 | $ 11,184,271 |
| Fortis Inc. | Management Fees(2) | 523,000 | 485,000 |
| | Internal Audit Services | - | 11,771 |
| | Interest on Short Term Financing | - | 3,948 |
| | Maritime Electric Directors' Expenses | 2,454 | 10,097 |
| | Maritime Electric Incentive Plan(3) | 218,264 | 197,460 |
| | Maritime Electric Share of Licenses, Memberships and Dues | 9,901 | 11,709 |
| NF Power Inc. | Maritime Electric Directors' Expenses | 4,678 | 8,331 |
| | Maritime Electric Share of Licenses, Memberships and Dues | 3,366 | 3,475 |
| | Insurance Claims Assistance | 1,292 | 930 |
| FortisOntario Inc. | Vehicle(4) | 39,557 | - |
| FortisAlberta Inc. | Maritime Electric Share of Licenses, Memberships and Dues | - | 250 |
| **Total** | | **$ 8,802,512** | **$ 11,917,242** |

(1) 2015 dividends includes $3,184,271 non-regulated dividend related to tax sharing agreement between Company and Fortis Inc. (see page 62 of General Rate Application).
(2) Costs disallowed in calculating the Company's annual revenue requirement per Order UE09-02.
(3) Fortis Inc. administers a stock option program on behalf of qualifying Company employees.
(4) Relating to acquisition of vehicle for employee transferring to Company.

GENERAL

**2. Provide a breakdown, by category, of the corporate services and support account (page 52 of original application) for costs incurred in 2014 and 2015 and the projected costs for 2016.**

**Response:**

2. The following schedule shows a breakdown of the 2014 and 2015 actual costs for the Corporate Services and Support account as well as the projected costs for the period 2016-2018:

| Corporate Services and Support | | | | | |
|---|---|---|---|---|---|
| **Description** | **2014 Actual** | **2015 Actual** | **2016 Forecast** | **2017 Forecast** | **2018 Forecast** |
| Employee Future Benefit Costs(1) | $ 1,098,600 | $ (89,400) | $ (1,075,000) | $ (1,066,600) | $ (1,054,100) |
| Employee Training | 61,152 | 21,035 | 32,700 | 33,700 | 34,700 |
| Human Resources | 144,519 | 138,749 | 171,100 | 160,300 | 165,100 |
| Insurance | 46,010 | 43,342 | 40,200 | 41,400 | 43,700 |
| Legal | 96,281 | 101,353 | 154,500 | 159,100 | 163,900 |
| Corporate Services(2) | 2,502,541 | 3,085,394 | 3,261,300 | 3,394,200 | 3,483,200 |
| Health, Safety and Environment | 91,213 | 94,236 | 171,700 | 176,800 | 181,700 |
| Internal Audit | 72,076 | 60,414 | 97,900 | 100,800 | 103,800 |
| Planning | 188,073 | 136,628 | 152,700 | 173,400 | 183,700 |
| **Total** | **$ 4,300,465** | **$ 3,591,751** | **$ 3,007,100** | **$ 3,173,100** | **$ 3,305,700** |

(1) Effective May 15, 2015 the Company implemented changes to the Employee Future Benefits Health Plan that resulted in actuarial gains that are required to be amortized over the 2015-2019 period.

(2) Includes labour and benefits costs for senior management and the administrative support group, trustee fees related to long term debt, bond and credit rating fees and other general administrative costs including maintenance agreements, postage, dues, fees and office supplies.

**GENERAL**

**3. With respect to Articles 4.1 and 4.2 of the 2016 General Rate Agreement between the Company and the Government of Prince Edward Island (the "Agreement"), explain the circumstances under which MECL may recover from customers funds for the RORA account. Why should customers wait until after this agreement expires before receiving any rebate of RORA earned during the contract period?**

**Response:**

3. **RORA as at December 31, 2015 (Article 4.1)**

As noted in Section 5 (page 11) of the amended and updated evidence filed with the Commission on February 5, 2016, the RORA refund period is proposed to be extended under the Agreement to three years in order to smooth the impact on customers' electricity costs over the Agreement term and assist in providing stable and predictable rate adjustments during the Agreement. Schedule 4-2 in Appendix B of the amended and updated evidence outlines the accumulation of the RORA balance with interest to December 31, 2015, and the forecast refund of the RORA balance from March 1, 2016 to February 28, 2019 under the Agreement.

The return of the RORA balance is proposed to be on a per kWh consumption basis and is based on the forecast electricity sales for the period March 1, 2016 to February 28, 2019 as outlined in Appendix 2 of the Agreement and results in the RORA rebate rates which are included as inputs in Appendix 2. Although the Company believes its sales forecast to be the best estimate at this time, inevitably actual sales results will differ from forecast during the three year term of the Agreement.

Where actual sales levels differ from the forecast levels in the Agreement, the RORA refunded to customers during the three years will also differ from that forecast in Schedule 4-2 of the Agreement. If sales levels exceed that forecast, the RORA amount refunded to customers will exceed the RORA balance owing to customers as at December 31, 2015, resulting in a net amount to be recovered from customers. Likewise, if sales levels are less than that forecast, the RORA amount refunded to customers will not be sufficient to fully refund the RORA balance as at December 31, 2015. To meet the Agreement's objective of providing stable and predictable rate adjustments during the three year term, Article 4.1 of the Agreement provides clarification that the disposition of any excess or shortfall with respect to the RORA balance will be addressed by the Commission at the end of the Agreement period.

**Potential RORA (2016 – 2018) – (Article 4.2)**

Article 4.2 of the Agreement is effectively a continuation of the terms of the current Section 48.1(9) of the Electric Power Act (EPA). This section of the EPA, however, is repealed effective March 1, 2016 thus requiring Article 4.2 to address the disposition of any RORA amounts that may occur during the three year term of the Agreement commencing March 1, 2019, after the Agreement expires.

Based upon the inputs used in the Agreement for the three year period, the Company does not forecast any new RORA amounts for 2016, 2017 or 2018. However, as noted above, the Agreement is based upon forecast values which will, in all likelihood, differ from actual results. Should the actual results (revenues and expenses) differ from forecast in such a manner that the Company's earnings would exceed the maximum allowed return on average common equity (ROE) of 9.35 per cent, Article 4.2 of the Agreement provides the mechanism by which any excess ROE amounts can be set aside as RORA during the term and returned to customers at the Commission's direction commencing March 1, 2019. Alternatively, should the variance of actuals results differ from the forecast inputs be considered material, Article 11.9 provides for an interim adjustment upon application to IRAC for approval.

GENERAL

**4. With respect to Schedule 9-2 of Appendix B of the amended application of the Company dated February 5, 2016 ("amended application") provide an explanation of the NB/Cable Interconnection charges and an explanation of the Schedules 1, 2, 3c, 4, 9 and 10 charges.**

**Response:**

4. The NB/Cable Interconnection charges in Schedule 9-2 of Appendix B represent the following two new charges related to the new submarine interconnection that will be paid by all participants on the Maritime Electric transmission system:

**NB Interconnection**

This charge is associated with new transmission lines required to supply the two new submarine cables scheduled to be installed in late 2016. The new transmission lines in New Brunswick are for the sole use of the Maritime Electric transmission system and thus are a direct assignment facility. In accordance with the NB OATT, the Company must pay the Non-Capital Support Charge Rate as detailed in Schedule 9 of the NB Power OATT. The current Non-Capital Support Charge Rate in the NB OATT is 5.3 per cent of the costs of the direct assignment facilities. In 2017 the fees are estimated to be $787,900 for the period July 1 – December 31 and annually amount to $1,575,800 for 2018 and thereafter. These amounts represent the interconnection payments which are incurred under the OATT to operate the transmission system and will be recovered from the OATT participants on PEI. Maritime Electric's share is forecast to be approximately $622,500 in 2017 and $1,245,000 for 2018 and thereafter.

**Cable Lease**

Under the terms of the project, the Province of PEI will be financing the cable project at an estimated cost of $79 million (net of federal funding) and leasing the asset to the

Company for 40 years. Lease payments, based upon an approximate 3.5 per cent financing assumption provided by the Province, will commence on March 1, 2017 and will amount to $3,345,400 for 2017 and annually amount to $4,014,500 for 2018 thereafter. These amounts represent the gross lease payments which are incurred under the OATT to operate the transmission system and will be recovered from the OATT participants. Maritime Electric's share is forecast to be approximately $2,642,300 in 2017 and $3,172,000 for 2018 thereafter.

The following is a summary of the OATT charges to be collected from Maritime Electric customers during the term of the Agreement. The 3 year average for the years 2016 – 2018 are included:

**Network Integration Transmission Service** **$5,799,000**

Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load.

**Schedule 1 – Scheduling, System Control and Dispatch Service** **$230,000**

This service is required to schedule the movement of power through, out of, within, or into a control area in a reliable manner. All Transmission Customers on PEI (including Maritime Electric) which use the Transmission System must pay for this service.

**Schedule 2 – Reactive Supply and Voltage Control from Generation Sources Service** **$372,000**

This is an ancillary service that is solely provided by the System Operator and is a mandatory service for all Transmission Customers. It is required in order to maintain, within acceptable limits, transmission voltages on the transmission facilities in Prince Edward Island. Maritime Electric's System Operator directs the operation of voltage control equipment to achieve this.

**Schedule 3c – AGC and Load Following for Wind Generators (NB Power OATT)** **$0**

This is an ancillary service that is supplied by NB Power that combines AGC and load following required to address the aggregate impact of non-dispatchable wind generation within the Balancing Authority Area. It is passed though the Maritime Electric OATT and charged directly to all wind generators located within the Balancing Authority Area. All wind farms located in the area are responsible for paying for or self-supplying this service.

**Schedule 4 – Energy Imbalance Service** **$0**

This is a service provided when a difference occurs between the expected and the actual hourly injection or withdrawal from the Transmission System. Energy Imbalance Service will be settled between the Transmission Provider (Maritime Electric) and the party responsible for the relevant transaction using the New Brunswick System Operator final hourly marginal cost. If the Transmission Customer schedules correctly 100 per cent of the time, there will be no Energy Imbalance charge. If the Transmission Customer schedules too low, they must pay for the extra energy they were short at the Final Hourly Cost in NB. If they Schedule too high, they must sell their excess at the Final Hourly Cost in NB.

This is typically a pass through charge, however if there are restrictions on the interconnection with New Brunswick, Maritime Electric may provide energy imbalance service with its generation fleet.

**Schedule 9 – Non Capital Support Charge** **$74,900**

This is an Operating Maintenance and Administrative (OM&A) related carrying charge and shall include all indirect OM&A charges. This rate is applied to assets for which the Transmission Customer has been assigned an obligation to make support payments to a Transmission Provider (Maritime Electric). A Direct Assignment for the interconnection of a generator that is paid for by the Transmission Customer but maintained by the

Transmission Provider is one such example. In addition to the Non-Capital Support Charge Rate, the Transmission Customer will be billed monthly on a time and materials basis for all direct OM&A costs (labour, material and transportation) associated with the Direct Assignment Facilities.

**Schedule 10 – Residual Uplift** **$0**

Residual Uplift provides a periodic settlement of various Transmission Provider's expenses and revenues that are not reflected in other schedules in the Maritime Electric OATT. Maritime Electric uses this to recoup generation costs due to wind generators being off schedule during times of curtailment in New Brunswick. The generator who supplied the energy, bills the Maritime Electric OATT Administrator who in turn charges the wind farm who was responsible for the shortage during the curtailment.

All of the above amounts are provisional and will be based upon the actual proration of charges amongst current transmission users. The Company intends to file an updated OATT Application with the Commission in 2016 to obtain approval for rates effective March 1, 2017. The Company does not foresee any significant changes, other than the incorporation of the NB interconnection charges and cable lease amounts noted above.

## GENERAL

**5. During the period from March 1, 2016 to February 28, 2019, under what circumstances would the Company seek Commission approval for an amendment to the ECAM base rate as set out in paragraph 2 of the proposed order in the amended application?**

**Response:**

5. The Company would only anticipate seeking Commission approval for an amendment to the ECAM Base Rates set out in Appendix 2 of the Agreement and paragraph 2 of the proposed Order if there has been a material change in circumstances as contemplated by Article 11.9 of the Agreement. As discussed in the General Rate Application evidence, during the term of the PEI Energy Accord the ECAM Base Rate has been transitioned to reflect the energy supply cost forecast. In the Agreement, the Company proposes to continue setting the ECAM Base Rate on March 1 of each year at the forecast rate per kWh for energy supply costs during the upcoming year.

As noted in Section 6 of the General Rate Application evidence, the Energy Purchase Agreement with NB Power has been extended for an additional three years to February 28, 2019. This extension allows the Company to reasonably estimate the average unit cost of energy purchases for the three year period covered by the Agreement, barring any unplanned events (for example, unplanned outages at Point Lepreau or curtailments in excess of forecast amounts). In addition, with NB Power's recent one year extension of an existing capacity agreement and an incremental increase in firm transmission service to PEI of 50MW, the risk of significant curtailments has been reduced.

As a result, the Company does not foresee a material circumstance occurring with respect to energy supply costs that would cause it to seek amendment to the Base Rate by the Commission.

**RATES - SCHEDULE 9-1 OF REFILED APPLICATION**

**6. With respect to Schedule 9-1, page 21 of the amended application, provide an explanation of the "Provincial Costs Recoverable" of $41.81.**

**Response:**

6. There has been no change to the Provincial Costs Recoverable included in Schedule 9-1 in the Agreement from those proposed to the Commission in the Application.

Provincial Costs Recoverable is discussed in Section 4 of the Application. Under the PEI Energy Accord, certain costs assumed by the Province of PEI during the Accord for extraordinary costs incurred during the Point Lepreau Generating Station Refurbishment and to exit the Dalhousie Generating Station participation agreement were deemed to be debts owing by Maritime Electric Customers to the Province. The EPA further states that Maritime Electric, acting as an agent for the Province, is to recover these amounts from customers, through rates, and remit them to the Province.

Schedule 4-1 of the Application shows the amount included in rates for the years 2011-2016 to fund repayment of the debt associated with these costs financed by the Province under the Accord. The Application further proposed in Section 4.5 that the existing rate of $0.00536/kWh continue to be recovered through rates beyond 2016 for these extraordinary costs incurred and financed by the Province.

In the case of a typical residential customer consuming 650 kWh per month (7,800 kWh per year) as shown in Schedule 9-1, page 21 of the amended Application, the amount collected annually would be 7,800 kWh X $0.00536 = $41.81.

## RATES - SCHEDULE 9-1 OF REFILED APPLICATION

**7. What is the current balance of the existing Cable Contingency Fund and when will this fund be fully replenished? Will the new cables require a new Cable Contingency Fund and if so what is the projected balance of this fund?**

**Response:**

7. Under the current Interconnection Lease Agreement, the Province of PEI leases the existing submarine cables and related infrastructure to the Company for a nominal annual amount. The Interconnection Lease Agreement also provides for the establishment of a $3.0 million Cable Contingency Fund which is owned and managed by the Province. As noted in Section 4.4 of the General Rate Application evidence, the accumulated balance in the Cable Contingency Fund was utilized to fund a significant portion of the costs related to the 2012 cable leak.

As a result, Maritime Electric and the Province agreed, as part of the PEI Energy Accord that the Fund would be replenished through a collection from customers over a ten year period commencing March 1, 2013 at a rate of $0.00027/kWh. This rate was based upon sales projections used in developing the Accord and was expected to generate an annual contribution to the Fund of approximately $300,000 per year over a ten year period. A portion of this amount will be recovered from other users of the cable in accordance with approved OATT charges. As of February 5, 2016 (the last remittance by Maritime Electric for January 2016 collections), the balance in the Fund was $898,875.73 which includes $3,553.26 of accumulated interest. Although contributions to the Fund will be subject to kWh sales levels in the coming years, it is expected that the Fund will be fully replenished within the ten year collection period originally planned.

To date the Company and the Province have not finalized the terms and conditions of the new interconnection agreement. However, it is reasonable to expect that the new interconnection agreement will require a similar contingency fund in the future to protect all parties from any unplanned costs related to the new submarine cable and related infrastructure. The target balance of any new fund is not known at this time but will be addressed during the course of developing the new interconnection agreement.

**RATES - SCHEDULE 9-1 OF REFILED APPLICATION**

**8. Is the cost recovery from the recently announced replacement cables included in the 2.3% rate increase? What is the estimated capital cost of the cable replacement project? How much of this amount is to be recovered from ratepayers and over what time period?**

**Response:**

8. Yes, the proposed 2.3 per cent annual increase in electricity costs for the typical customer in each rate class during the three year term of the Agreement does provide for recovery of the costs related to the new submarine cable project.

As discussed in IR4, the costs of new submarine cable project are comprised of the following two amounts:

**NB Interconnection**

This charge is associated with new transmission lines required to supply the two new submarine cables scheduled to be installed in late 2016. The new transmission lines in New Brunswick are for the sole use of the Maritime Electric transmission system and thus are a direct assignment facility. In accordance with the NB OATT, the Company must pay the Non-Capital Support Charge Rate as detailed in Schedule 9 of the NB Power OATT. The current Non-Capital Support Charge Rate in the NB OATT is 5.3 per cent of the costs of the direct assignment facilities. In 2017 the fees are estimated to be \$787,900 for the period July 1 – December 31 and annually amount to \$1,575,800 for 2018 and thereafter. These amounts represent the gross interconnection payments which are incurred under the OATT to operate the transmission system and will be recovered from the OATT participants. Maritime Electric's share is forecast to be approximately \$622,500 in 2017 and \$1,245,000 for 2018 thereafter.

**Cable Lease**

Under the terms of the project, the Province of PEI will be financing the cable project at an estimated cost of $79 million (net of federal funding) and leasing the asset to the Company for 40 years. Lease payments, based upon an approximate 3.5 per cent financing assumption provided by the Province, will commence on March 1, 2017 and will amount to $3,345,400 for 2017 and annually amount to $4,014,500 for 2018 thereafter. These amounts represent the gross lease payments which are incurred under the OATT to operate the transmission system and will be recovered from the OATT participants. Maritime Electric's share is forecast to be approximately $2,642,300 in 2017 and $3,172,000 for 2018 thereafter.

The Company's share of these costs is considered a component of energy supply costs and, as such, is included in the ECAM for recovery from customers. To the extent that these costs differ upon completion of the project from that forecast in the Agreement, the difference will be captured in the ECAM account until after the Agreement.

**DEPRECIATION**

**9. Under which section of the *Electric Power Act* are you requesting the revised depreciation rates be effective as of January 1, 2016?**

**Response:**

9. Maritime Electric is applying pursuant to section 12 of the Island Regulatory and Appeals Commission Act, RSPEI 1988, Cap. I-11 ("IRAC Act"), as well as sections 26, 48(1)(b) and 48.1(1)(b) of the *Electric Power Act*, RSPEI 1988, Cap. E-4 ("Act").

**DEPRECIATION**

**10. Does the Commission have jurisdiction to amend depreciation rates for MECL before March 1, 2016? To recover the requested depreciation of the CGS for 2016, what rate of depreciation would be required if the date for the implementation if March 1, 2016?**

**Response:**

10. Yes, section 12 of the IRAC Act provides the Commission with authority, in its absolute discretion, to review, rescind or vary any order or decision made by it, or to rehear any application before deciding it. Although certain orders and obligations of the Commission were varied or terminated pursuant to subsections 48(7) and 48.1(8) of the EPA, the Commission's orders relating to depreciation were not varied or terminated and remain outstanding. The most recent Commission orders with respect to deprecation (UE07-01 and UE08-07) require Maritime Electric to apply existing deprecation rates until further ordered by the Commission. Section 12 of the IRAC Act authorizes the Commission to vary these orders to apply appropriate and reasonable rates of deprecation. This authority is not impacted by the legislative amendments implemented through the Accord.

Additionally, the Commission retains general supervisory authority over public utilities, including Maritime Electric. This authority is not impacted by legislative amendments implemented through the Accord.

Finally, sections 48(1)(b) and 48.1(1)(b) of the Act provide the Commission with authority to regulate Maritime Electric's input factors, including depreciation, prior to March 1, 2016.

Appendix 6 of the amended and updated evidence outlines the proposed depreciation rates to recover the depreciation and accrued reserve variance for the Charlottetown

Thermal Generating Station effective January 1, 2016. If the date for implementation was delayed until March 1, 2016, two months of depreciation (January and February) would be recorded at the current rate of 2.5 per cent leaving the balance to be recovered in the remaining 10 months in order to recover the requested amounts in 2016. As a result, the monthly depreciation rates after February 29, 2016 would need to be adjusted and would result in the following monthly depreciation rates for the period March 1 – December 31, 2016 (note: the annualized total remains unchanged):

| Charlottetown Thermal Generating Station | Depreciation Rates per Appendix 6 (%) | | Revised Depreciation Rates March – December (%) | | |
|---|---|---|---|---|---|
| | Annual | Monthly (1/12) | Monthly (a) (Jan-Feb) | Monthly (b) (Mar-Dec) | Total Annual (2 x a + 10 x b) |
| Structures and Improvements | 9.35 | 0.779 | 0.208 | 0.8934 | 9.35 |
| Boiler Plant Equipment | 7.65 | 0.638 | 0.208 | 0.7234 | 7.65 |
| Turbogenerator Units | 8.20 | 0.683 | 0.208 | 0.7784 | 8.20 |
| Accessory Electrical Equipment | 5.14 | 0.428 | 0.208 | 0.4724 | 5.14 |
| Miscellaneous Power Plant Equipment | 6.99 | 0.583 | 0.208 | 0.6574 | 6.99 |

Depreciation rates for other capital assets would also require adjustment in 2016 to recover the proposed 12 month depreciation rate over a 10 month period as follows:

| Other Capital Assets | Depreciation Rates per Schedule 11-2 of the Application | | Revised Depreciation Rates March – December (%) | | |
|---|---|---|---|---|---|
| | Annual | Monthly (1/12) | Monthly (a) (Jan-Feb) | Monthly (b) (Mar-Dec) | Total Annual (2 x a + 10 x b) |
| Borden Generating Station | 4.81 | 0.400 | 0.208 | 0.4394 | 4.81 |
| Combustion Turbine #3 | 2.28 | 0.190 | 0.208 | 0.1864 | 2.28 |
| Transmission Assets | 2.27 | 0.189 | 0.192 | 0.1886 | 2.27 |
| Distribution Assets | 3.32 | 0.276 | 0.250 | 0.2820 | 3.32 |
| General Assets | 5.96 | 0.496 | 0.561 | 0.4838 | 5.96 |

## DEPRECIATION

**11. With respect to Appendix 2 of the proposed order in the amended application, provide a breakdown of the anticipated annual capital expenditures in each of the years 2017 and 2018.**

**Response:**

11. The following excerpt from Appendix B (Schedule 15-1) of the amended and updated evidence filed with the Commission on February 5, 2016 shows the breakdown of the 2015 actual and the 2016 - 2018 anticipated annual capital expenditures:

| Schedule of Capital Expenditures ($) | | | | |
|---|---|---|---|---|
| | **2015 Actual*** | **2016 Forecast** | **2017 Forecast** | **2018 Forecast** |
| **Generation** | | | | |
| Charlottetown Plant | $ 451,154 | $ 1,061,000 | $ 1,035,000 | $ 496,000 |
| Borden-Carleton Plant | 234,643 | 154,000 | 102,000 | 1,524,000 |
| | | | | |
| **Transmission & Distribution** | | | | |
| Transmission | 8,092,841 | 10,399,000 | 8,901,000 | 8,063,000 |
| Distribution | 16,132,068 | 17,538,000 | 18,010,000 | 19,207,000 |
| | | | | |
| **Corporate** | 897,584 | 1,214,000 | 1,045,000 | 1,205,000 |
| | | | | |
| Sub-total | 25,808,290 | 30,366,000 | 29,093,000 | 30,495,000 |
| Allowance for Funds Used During Construction | 376,452 | 200,000 | 200,000 | 200,000 |
| General Expense Capitalized | 458,433 | 494,000 | 507,000 | 521,000 |
| Less: Contributions | (382,693) | (400,000) | (400,000) | (400,000) |
| **Net Capital Expenditures** | **$ 26,260,482** | **$ 30,660,000** | **$ 29,400,000** | **$ 30,816,000** |

* *2015 includes $1,587,160 of carryover expenditures (net of contributions) approved in prior years.*

The 2016 capital expenditures represent those amounts approved by the Commission in Order UE15-01 dated November 3, 2015. The forecast expenditures by category for 2017 and 2018 represent preliminary forecast amounts and would be subject to annual Application, review and approval by the Commission.

## DEPRECIATION

**12. With respect to Schedule 12 - 11, page 80 of the original application of the Company dated October 21, 2015 ("original application"), what are the amortization rates associated with Intangible Assets? Provide a breakdown of assets in this category by asset class and fiscal year created.**

**Response:**

12. The Category of Intangible Assets is a CPA Canada Handbook accounting standard under Part II- Accounting Standards for Private Enterprises, Section 3064, Goodwill and Intangible Assets. The Company adopted the standard effective January 1, 2009, with restatement of the prior year opening balances at January 1, 2008. Prior to that, the assets were included with Property, Plant and Equipment (Fixed Assets).

The amortization rates for the Intangible Assets are as follows:

| | % |
|---|---|
| Internally Developed Software | 13.5 |
| Rights of Way and Easements | |
| Transmission | 2.3 |
| Distribution | 3.2 |

Intangible Assets represent the Company's internally developed software applications, which include the Company's Customer Information System and Energy Purchase System, and costs to acquire transmission and distribution Right of Ways and Easements.

The table below presents a breakdown of the Intangible Assets by asset class and the fixed year credited since reclassification from Property, Plant and Equipment on January 1, 2008 under the new CPA Standard.

| Year | Internally Developed Software | Rights of Way and Easements | | Total |
|---|---|---|---|---|
| | | Transmission | Distribution | |
| Additions By Year | | | | |
| 2007 & Prior | $ - | $ 1,597,813 | $ 155,312 | |
| 2008 | 1,181,175 | 2,187,918 | 126,688 | |
| 2009 | 54,820 | 557,786 | - | |
| 2010 | 44,812 | 73,533 | - | |
| 2011 | 85,157 | 8,031 | - | |
| 2012 | 79,016 | 13,565 | - | |
| 2013 | 201,408 | - | - | |
| 2014 | 296,214 | - | - | |
| Subtotal | 1,942,601 | 4,438,646 | 282,000 | 6,663,247 |
| Accumulated Amortization | (1,166,580) | (1,171,740) | (54,144) | (2,392,463) |
| 2014 - Net Asset | 776,022 | 3,266,907 | 227,856 | 4,270,784 |
| 2015 | 213,658 | 15,580 | - | 229,238 |
| Amortization - 2015 | (282,821) | (102,268) | (9,024) | (394,113) |
| 2015 - Net Asset | 706,858 | 3,180,219 | 218,832 | 4,105,909 |

**FINANCIAL**

**13. The cost of service study discussed in Section 13 of the Application demonstrates that Residential Customers have not been paying the full costs of providing service to them, but that General Service customers have been paying more that they cost of service. Is this correct?**

**a. The amended application proposes delaying changes to the second block discount rates until a further detailed study is completed. Is this correct?**

**<u>Response:</u>**

13. a. The objective of a cost allocation study is to allocate the cost of providing service to rate classes on a cost causation basis; therefore, a revenue to cost ratio (RTC) below 100 per cent indicates revenue should be increased for that rate class while a ratio above 100 per cent indicates that revenue for that rate class should be lower. The Company has proposed a RTC range of 90/110 as an acceptable range for the utility's rate classes.

Section 13.4 of the General Rate Application outlines the results of the 2014 Cost Allocation Study. In particular, Schedule 13-4 of the Application presents a comparison of the RTCs for each rate class which demonstrates that based upon the 2014 results, certain classes (General Service, Lights and Unmetered) are providing revenue in excess of their allocated costs while other classes (Residential and Small Industrial) are not providing revenue sufficient to cover the allocated costs.

The General Rate Agreement filed with the Commission on January 29, 2016 proposes to defer the implementation of the Residential second block and related General Service changes until after the Agreement. During the period of the

Agreement the Company proposes to conduct a Point Lepreau Classification Study, a rate design study for farms (which are included in the Residential rate class) as well as another Cost Allocation Study (based on 2017 financial results) all of which have the potential to yield changes to the RTCs for the Residential and General Service rate classes derived from the 2014 Cost Allocation Study. In addition, deferral of the second block changes will allow the Company to consider any short or long term policies, programs and approaches to energy and sustainability as a result of the Provincial Energy Strategy that the Government of PEI will be developing in 2016, as well as the impact of the Company's new DSM program.

**FINANCIAL**

**13. The cost of service study discussed in Section 13 of the Application demonstrates that that Residential Customers have not been paying the full costs of providing service to them, but that General Service customers have been paying more that the cost of service. Is this correct?**

**b. Is it correct (based on page 9 of the original application) to say that maintaining the current second block rate system is estimated by Maritime Electric to be a subsidy of $773,000, over term of the Agreement, to that portion of the residential customer class consuming over 2000 kwh/month?**

**Response:**

13. b. To the extent that RTCs do not equal 100 per cent in each rate class it can be argued that there is cross-subsidization between the various rate classes. However, it is recognized that cost allocation studies are based upon results at a point in time as well as a number of assumptions and allocation methodologies which, if changed, could have a resulting impact upon the RTCs of the rate classes. The Company has proposed a RTC range of 90/110 as an acceptable range for the utility's rate classes.

The results of the 2014 Cost Allocation Study indicate that the Residential rate class is within the recommended target RTC range of 90/110 although the General Service class is outside the range. The original proposal to adjust the residential second block and general service rates, and shifting an estimated $773,000 in revenue, was expected to lower the General Service RTC while maintaining the Residential RTC within the recommended 90/110 range. However, for the reasons noted in response to IR14, the Company is proposing to defer this change until after the Agreement expires.

**FINANCIAL**

**14. Why should the Commission delay implementation of the second block rate changes proposed by MECL in the original application? Are you aware of any other jurisdiction in North America which has a discounted pricing structure for greater energy consumption by residential customers?**

**<u>Response:</u>**

14. The Company's evidence in the General Rate Application (see Schedule 13-7) concluded that only PEI retains a declining rate block structure for the Residential rate class in comparison to other jurisdictions in Canada. The Company is not aware of any other jurisdictions in North America with a discounted pricing structure in the Residential rate class.

The General Rate Agreement represents the outcome of a collaborative approach taken by the Province of PEI and Maritime Electric to develop an acceptable resolution to a number of matters, including those raised in the General Rate Application and the Depreciation Study Application. During the course of the discussions to develop the Agreement both parties agreed, for a number of reasons, that the proposed changes to the residential multi-block rate structure should be deferred until after the end of the Agreement.

The Province has indicated its intention to develop a Provincial Energy Strategy with a focus on sustainability as well as cost effective energy efficiency and conservation approaches, including renewable energy alternatives. The deferral will allow the Company to consider any short or long term policies, programs and approaches to energy and sustainability arising from the Provincial Energy Strategy.

In Order UE15-02, the Commission approved only the public outreach and education component of the Company's demand side management and energy conservation (DSM) plan indicating it will issue another order in due course for the Company to refile a new DSM plan with the Commission. Although the Company believes the proposals in the original DSM filing were cost-effective targeted plans to reduce peak load and energy consumption in the commercial and residential classes, the new plan will need to consider the requirements of the Commission's new order and also align with the direction of the Provincial Energy Strategy.

The Lepreau Classification Study proposed by the Company, as outlined in Section 13.4 B(ii) of the General Rate Application could have a material impact on the RTC for the certain rate classes.

Finally, after filing the General Rate Application on October 28, 2015 the Company held discussions with representatives from the farming community to review the proposed changes to the residential multi-block rate structure. The Company recognizes that the inclusion of farms in the residential rate class may not be appropriate given the differences in load and consumption for these customers and has proposed to undertake further study of this matter by performing a Rate Design Study. Possible outcomes include some or all farms remaining in the residential rate class, moving to commercial classes or moving to a separate farm rate class.

With the proposed Agreement extending the rate setting period to February 28, 2019, the Company believes the timeline for the Rate Design Study for farms should be extended for filing to April 30, 2018 in order to have the most current information included. As such, it is the Company's view that the residential multi-block rate structure changes should be deferred until a determination and recommendation with respect to farms can be presented to the Commission for consideration.

FINANCIAL

**15. With respect to the weather normalization mechanism and reserve, under what section of the *Electric Power Act* does the Commission have jurisdiction to order this effective January 1, 2016? What are the implications of changing the effective date to March 1, 2016?**

**Response:**

15. **Jurisdiction**

The weather normalization mechanism establishes an input factor to be used by the Company. The Company is not requesting a change in rates, tolls and charges; however, is requesting that, in order to provide an accurate weather normalization calculation for the year, the weather normalization mechanism be calculated commencing on January 1, 2016. Sections 48(1)(b) and 48.1(1)(b) authorize the Commission to establish appropriate input factors, such as the weather normalization mechanism, for the Company that are not identified in the Act.

**Implication of Changing the Effective Date**

As illustrated in Appendix 6 - Schedule 2 of the General Rate Application evidence, historically January and February are the highest Heating Degree Day (HDD) months during the year. As a result, to the extent that actual HDD results differ from historical average, the HDD variation is expected to be more pronounced in these months and the associated adjustment to the Weather Normalization Reserve is expected to be greater.

The impact of changing the effective date to March 1, 2016 is ultimately determined by the variation of the actual HDD experience in January and February 2016 as compared to the 10 year historical average. Preliminary estimates for January 2016 indicate that actual HDD variance from average was (41) HDD which means January 2016 was warmer than average. If the Weather Normalization Reserve is approved effective

January 1, 2016, this would result in the Company recording incremental revenue and a related amount recoverable from customers of approximately $86,000 as illustrated below:

| | |
|---|---|
| HDD - January 2016 | 713 |
| Less: HDD – Average | 754 |
| Variance | (41) |
| Multiply by: HDD Coefficient | 41.73 |
| MWh | 1,710.93 |
| Multiply by: Net Marginal Revenue | 50.42 |
| Weather Normalization Adjustment | $ 86,265.09 |

The impact for the month of February 2016 is not yet available.

## FINANCIAL

**16. Please provide particulars of cost saving initiatives to be implemented over the term of this agreement which will result in customer savings.**

**Response:**

16. Cost savings are realized through a variety of measures that can be broadly characterized as:

- Electrical loss reduction
- Reliability improvement
- Labour and material cost reduction
- Process improvements
- Strategic use of technology

The Company has not assigned a dollar value to all of its initiatives but has generally incorporated continuous improvement in its forecasts by keeping staffing levels within a reasonable bandwidth, forecasting minimal changes to Company use and system losses despite increased customer usage and at the same time striving to improve reliability and maintaining effective levels of cost control.

The following initiatives will be continued or implemented over the term of the Agreement.

- Generation Initiatives:

    - Transitioning from two training runs per year to one training run at the Charlottetown Thermal Generating Station (CTGS) (reduced overtime and fuel expense).

- Use of cross trained ECC Operators to minimize labour costs.
- Introduction of Spare Combustion Turbine Operators to help manage the need for additional staff.
- Reduction of Production staff and the implementation of cross training and redeployment when the CTGS is not operating.
- Capital expenditures at the CTGS limited to reliability and safety criteria near term to match the timeline for the decommissioning of plant units.
- Continuous review of projects and need (i.e. - unit #7 overhaul changed from overhaul to addition of vibration and temperature monitoring).

- Transmission and Distribution Initiatives:

  - The installation of capacitor banks at Lorne Valley and the Charlottetown Thermal Generating Station will improve system efficiency and reduce losses by supporting area voltage.
  - The new 138 kV transmission line Y-104 running east from West Royalty to Church Road, Saint Charles will improve power system efficiency through reduced losses as noted in the Company's prior Capital Budget applications.
  - Annual distribution line rebuilds include replacement with conductors of greater sizes. This contributes to reducing system losses. Electrical loss analysis is a key component in all infrastructure planning.
  - The vegetation management program will expand over the period and reduce outages associated with tree contracts, and power line damage from trees during weather related events and the resulting after hour crew call-outs.
  - The establishment of new distribution substations will improve system efficiency through reduced system losses.

  - The conversion of high pressure sodium street and area lighting units to LED units contributes to a reduction of on-going lighting maintenance costs.
  - Strategic use of technology in all departments of the Company will improve business efficiency. Examples of systems being developed or improved upon:
    - ✓ *Customer Business* – On-line Service Requests;
    - ✓ *Operation Support* – Work Order Management System Improvements, Greater use of LIDAR Surveying technology;
    - ✓ *Damage Assessment/Visual Inspection* – Use of Drone technology; and
    - ✓ *Meter Reading Route Optimization* – Conversion of demand meters to RF technology.
  - Installation of heat pumps at Company owned facilities will reduce heating costs at the facilities.

- <u>General and Administrative Initiatives:</u>

  - Forecast regulatory costs for 2016 were reduced by $207,000 from the Application to reflect the expected savings associated with a shorter regulatory hearing process including lower legal and professional fees. These reductions were also factored into the inputs established for 2017 and 2018.
  - In an effort to reduce corporate service costs, the Company introduced changes to its sponsored health benefit plans in 2015 to lower future employee benefit costs. The benefit of these changes is being amortized over five years and will result in savings of $1.3M per year over this period. The net recovery from 2016 – 2018 is approximately $1.1M per year (see response to interrogatory #2).

**FINANCIAL**

**17. MECL's Schedule of Interest Expense on Long Term Debt (Schedule 12-4 of the original application) includes some debt with higher than currently available borrowing rates. Has MECL done an analysis to determine if this debt can be retired or re-negotiated to take advantage of current borrowing rates?**

**Response:**

17. The terms and conditions of the Company's long term debt issues are governed by its Trust Deed and associated Supplementary Indentures. Review of these documents indicates that there is no way by which higher interest rate debt issues can be replaced by lower interest debt in such a manner that overall borrowing costs could be lowered. Under the Trust Deed and associated Supplementary Indentures, the Company is permitted, under specific circumstances to redeem or pay-out certain long-term debt issues. However, when such a redemption is initiated, the Company is required to pay all interest on the debt normally payable from the date of redemption up to the original maturity date thereby eliminating any savings to be gained from a lower interest rate.

## FINANCIAL

**18. Have the changes in the *Electric Power Act* increasing the debt to equity ratio and capping the equity component at 40% resulted in higher borrowing costs for MECL?**

**Response:**

18. During the Fall sitting of the PEI Legislature, the Government of PEI passed legislation to amend the Electric Power Act. One of the legislative changes was, effective January 1, 2017, a reduction of the Company's minimum common equity component to be maintained at all times from 40 per cent to 35 per cent and the establishment of a maximum 40 per cent common equity component for year.

Since the Company has historically maintained less than 60 per cent of its capital structure in the form of debt, the legislative changes will result in higher than historical related debt levels.

The interest rates charged under the Company's $50 million committed unsecured revolving credit facility with TD are based upon the Corporate Credit Rating assigned to the Company by the independent rating agency Standard & Poor's (S&P). The last annual ratings update performed by S&P was issued on March 31, 2015, prior to the enactment of the legislative changes to the Company's capital structure (Appendix 7 of the General Rate Application filing). At that time the Company was assigned a BBB+ (Stable) rating based upon an "Excellent" business risk and "Aggressive" financial risk profile and S&P's expectation that the Company will continue to generate stable cash flow during the two-year outlook horizon with no adverse regulatory or governmental rulings.

One of the assumptions used by S&P in their March 31, 2015 ratings update was that there will be no material changes to the return on equity and capital structure of 40 per cent equity and 60 per cent debt in Maritime Electric's next rate setting in 2016. Whether S&P views the legislative changes to the Company's capital structure as material, thus requiring a downgrade in the Company's credit rating will be determined during S&P's annual update which is expected to be issued in March 2016.

Should the Company's Corporate Credit Rating be reduced from BBB+ to BBB, borrowing costs under the TD facility will increase by as much as 25 basis points (0.25 per cent) depending upon the type of borrowing. In addition, a downgrade would also negatively impact the borrowing rate on any long term debt financing that the Company may issue in the future. To date, there has not been any downgrade in the Corporate Credit Rating due to the legislative changes to the Company's capital structure and thus no increase in related borrowing costs.

**FINANCIAL**

**19. With respect to Appendix B, Schedule 9-1 of the amended application, there is a significant increase in OATT expense in 2017 and 2018, please explain.**

**Response:**

19. The significant increase in OATT expense found in Schedule 9-1 is due substantially to the introduction of costs associated with the lease of the new cables and related NB interconnection costs discussed below.

A detailed breakdown of the OATT expense in Schedule 9-1 of the amended and updated evidence can be found in Appendix B, Schedule 9-2. The following provides further information on the nature of the new interconnection related costs:

**NB Interconnection Charges**

This charge is associated with the new transmission lines required to supply the two new submarine cables being installed in late 2016. The new transmission in New Brunswick is for the sole use of the Maritime Electric transmission system and thus is a direct assignment facility. In accordance with the NB OATT, the Company must pay the Non-Capital Support Charge Rate as detailed in Schedule 9 of the NB Power OATT. The current Non-Capital Support Charge Rate in the NB OATT is 5.3 per cent of the costs of the direct assignment facilities. In 2017 the fees are estimated to be $787,900 for the period July 1 – December 31 and annually amount to $1,575,800 for 2018 thereafter. These amounts represent the gross interconnection payments which are incurred under the OATT to operate the transmission system and will be recovered from the OATT participants. Maritime Electric's share is forecast to be approximately $622,500 in 2017 and $1,245,000 for 2018 thereafter.

**Cable Lease**

Under the terms of the project, the Province of PEI will be financing the cable project at an estimated cost of $79 million (net of federal funding) and leasing the asset to the Company for 40 years. Lease payments, based upon an approximate 3.5 per cent financing assumption provided by the Province, will commence on March 1, 2017 and will amount to $3,345,400 for 2017 and annually amount to $4,014,500 for 2018 thereafter. These amounts represent the gross lease payments which are incurred under the OATT to operate the transmission system and will be recovered from the OATT participants. Maritime Electric's share is forecast to be approximately $2,642,300 in 2017 and $3,172,000 for 2018 thereafter.

## FINANCIAL

**20. With respect to Appendix B, Schedule 15-1 of the amended application, please explain the expenditure planned for Borden-Carleton generation in 2018.**

**Response:**

20. The planned expenditures for the Company's Borden Generating Station in 2018 are as follows:

| | |
|---|---|
| ▪ Enclosure renovations (provisional) | $26,000 |
| ▪ Miscellaneous combustion turbine improvements (provisional) | $72,000 |
| ▪ Engine overhaul on CT1 | $1,426,000 |
| | $1,524,000 |

The overhaul of the Rolls Royce Avon Engine on Combustion Turbine #1 (CT1) is an Original Equipment Manufacturer (OEM) recommendation based upon the age of the unit which was installed in 1971. This was initially planned for 2016; however, in consideration of the low hours of operation the project was moved to 2018. The breakdown of costs for this work is as follows:

| | |
|---|---|
| ▪ OEM contract | $950,000 |
| ▪ Internal labour | $126,000 |
| ▪ Contingency and provision for findings | $350,000 |
| | $1,426,000 |

## ENERGY SUPPLY

**21. Is there a signed contract with NB Power which will provide firm, contractual energy and transmission necessary to provide reasonably safe and adequate service over the term of the Agreement? If so, please provide a copy.**

**<u>Response:</u>**

21. On February 9, 2016, the Company provided three agreements to the Commission, on a confidential basis, as the documents contain sensitive commercial information related to energy supply.

As well, the New Brunswick Power System Operator (formerly NBSO) recently published the following on their website:

> ***<u>Engineering Study – Additional Firm Capacity to NSPI + MECL</u>***
> *NB Power Transmission and the System Operator have completed new studies regarding the firm transfer capability between New Brunswick and its Nova Scotia/PEI interconnections. The results of these studies are as follows:*
>
> - *With minimal transmission system re-configurations/upgrades, the total firm transfer capability between New Brunswick and its Nova Scotia/PEI interconnections can be increased from 80 MW to 200 MW, an incremental increase of 120 MW.*
> - *This incremental increase is sufficient to provide the 50 MW of new firm transmission service between New Brunswick and PEI presently queued on OASIS.*
> - *Pending final confirmation the remaining 70 MW of new incremental firm transmission service between New Brunswick and its Nova Scotia/PEI interconnections will be subject to an open season as set out in the New Brunswick Open Access Transmission Tariff.*

The second bullet above indicates that the addition 50 MW of new firm transmission service between New Brunswick and PEI that had been requested for several years will be approved. This will enable the purchase of an additional 50 MW of capacity. Maritime Electric and NB Power are in discussions to finalize these arrangements.

## ENERGY SUPPLY

**22. With respect to Appendix B, Schedule 8-3 of the amended application, MECL is projecting increases in firm energy purchases and decreases in system energy purchases over the term of this agreement. Please explain.**

**Response:**

22. As purchases from Point Lepreau and wind are tied to existing generation, the purchases from NB Power essentially are forecast to supply the balance of Maritime Electric's energy supply requirement, net of a small amount of provisional production from the Company's generating units. The gradual increase in firm energy purchases is needed to accommodate the following:

- load growth
- the expiry of an existing capacity agreement
- the reduction in capacity from the CTGS to CT4 (or its replacement source of capacity) which is a decrease of 5 MW (55 MW to 50 MW).

The firm capacity purchases are forecast to increase as follows:

| | 2015 Actual | 2016 Forecast | 2017 Forecast | 2018 Forecast |
|---|---|---|---|---|
| **Capacity (MW)** | 40 | 40 | 60 | 70 |

**POINT LEPREAU**

**23. What is the Point Lepreau Classification study and what is its purpose?**

**Response:**

23. The Point Lepreau nuclear generating facility is a base load facility with substantially all costs treated as fixed long term facility costs with relatively minor fuel costs. In the 2014 Cost Allocation Study filed with the General Rate Application (Appendix 10), the annual fixed costs incurred under the Lepreau participation agreement are classified as all demand related with the minor fuel cost component classified as energy.

In assessing the results of the 2014 Cost Allocation Study, the Company did conduct sensitivity analysis with respect to the classification of the annual fixed costs under the Lepreau participation agreement. The sensitivity analysis examined the impact on revenue to cost ratios for each rate class if the Lepreau fixed costs were classified as energy rather than demand. The results of the analysis were presented in Schedule 13-5 of the General Rate Application and demonstrated a potential material impact on the revenue to cost ratios for certain rate classes.

The Point Lepreau Classification Study will involve a detailed review and analysis of the Lepreau costs to determine the most appropriate methodology to be employed in future Cost Allocation studies to best classify the annual fixed costs associated with the Point Lepreau participation agreement between demand and energy. One such methodology to distinguish between demand and energy related costs would be to compare the baseline cost of providing capacity (demand related), such as the cost of a simple cycle combustion turbine, to the fixed costs incurred for Lepreau. The excess of the fixed Lepreau costs over the baseline cost of providing capacity could be considered energy related as they represent the costs incurred to provide lower cost energy.

## DEMAND SIDE MANAGEMENT

**24. What annual budget amount has been included in the Schedule of Inputs for DSM?**

**Response:**

24. In Order UE15-02 issued on November 3, 2015, the Commission indicated that it will issue a new Order on the matter of Demand Side Management in due course. As stated in Section 8 of the amended and updated evidence filed with Commission on February 5, 2016, the financial inputs into the 2016 General Rate Agreement reflect Demand Side Management expenditures similar to the original filing on June 3, 2015. The Company and the Province agreed that these amounts were prudent to fund any revisions to the original plan.

The schedule below shows the annual provisional expenditures for DSM and related amortization to be recovered from customers through rates:

| Demand Side Management Plan | | | |
|---|---|---|---|
| | **2016 Forecast** | **2017 Forecast** | **2018 Forecast** |
| Annual DSM Expenditures | $ 1,655,900 | $ 2,198,400 | $ 2,279,400 |
| Annual Amortization to be Recovered Through Rates(1) | - | $ 322,500 | $ 573,000 |

(1) including amounts allocated for community outreach activities.

## DEMAND SIDE MANAGEMENT

**25. What are the rate consequences over the term of the Agreement if no DSM plan is approved or a DSM plan is approved for a different value than budgeted in the Schedule of Inputs?**

**Response:**

25. As discussed in response to IR24, the Agreement assumes an expenditure level consistent with the DSM application previously filed with the Commission. These expenditures are also assumed to be recovered as a component of the ECAM in the manner proposed in the DSM application and as ordered by the Commission for the public outreach and education expenditure.

The forecast amount to be recovered through the ECAM is $322,500 and $573,000 for 2017 and 2018 respectively. These annual amounts amortized through the ECAM include the $167,500 annual budget amount for the public outreach and education expenditures approved by the Commission in Order UE15-02. As a result, the net amount of DSM expenditures in the Schedule of Inputs for which future Commission approval is required is $155,000 in 2017 and $405,500 in 2018. These amounts are not considered material as they represent only 0.08 per cent of revenue in 2017 and 0.21 per cent of revenue in 2018 and therefore would not have any impact on customer electricity costs during the term of the Agreement.

It is the Company's view that Section 6.5 of the Agreement would permit Maritime Electric to defer any difference between the DSM amounts assumed in the Agreement and the actual amount, if any, ordered by the Commission.

**RATE OF RETURN**

**26. Attached find reports issued by Concentric Energy Advisors and Ontario Energy Board ("OEB") staff relating to Cost of Capital and Equity Returns. Please provide commentary rationalizing the agreed upon ROE of 9.35% in the Agreement with the analysis of these reports. Please advise on the Company's estimates of risk premiums which should be paid to MECL as a result of its size, location or other unique factors.**

**Response:**

26. The Concentric Energy Advisors May 1, 2015 newsletter provides information on the authorized ROEs for Canadian and US Gas and Electric Utilities. In Section 12 of the Company's General Rate Application evidence information similar to that of the Concentric newsletter was presented and discussed. Schedule 12-9 of the Application outlines the 2014 allowed and earned ROEs and the 2015 allowed ROEs for Canadian and the US group electric utilities.

As noted in the evidence, the difference between the allowed ROE and earned ROE occurs because of differences in the manner in which other jurisdictions establish ROE and revenue requirement as compared to PEI. The Agreement proposes that Maritime Electric continues to be regulated by having a cap on ROE for purposes of determining revenue requirement whereas regulators in other jurisdictions will determine revenue requirement based upon an allowed or target ROE. Utilities are then permitted, if they are successful in doing so, to earn above the allowed or target ROE. The result has been other Canadian utilities, which the Commission has previously recognized as having lower risk than Maritime Electric, have been permitted to earn returns above their target ROE and at levels near those of the Company.

In reviewing Table 2: Summary of Cost of Capital Parameters of the OEB report it is noted that the average of the target ROE for Ontario utilities for the period 2010 – 2011 was 9.63 per cent which represents a 0.12 per cent difference between the last ROE decision by IRAC setting the Company's maximum ROE at 9.75 per cent. Similarly, the January 2016 OEB decision set the target ROE at 9.19 per cent which is 0.16 lower than the proposed 9.35 per cent ROE for Maritime Electric in the Agreement.

The Commission has, for a number of reasons, recognized in past Orders that the Company has a higher overall risk profile relative to other Atlantic Canadian electric utilities and comparable Canadian utilities. The factors leading to this higher overall risk profile have not substantially changed from prior years and continue to impact both the business risk (operating and regulatory risk) and financial risk profile of the Company.

The Company is subject to greater operating risk from both adverse economic developments and damaging weather events due to its smaller relative size and Island location resulting in a concentration of customers and assets in a restricted geographic area. The loss of a significant customer (e.g., McCain facility closure in 2014) or a significant storm can impact the ability to recover costs in a timely manner resulting in increased borrowing costs and weakening capital structure. In addition, demographic changes in the service territory are expected to dampen the long term growth rate of the PEI economy which could restrict sales growth, cash flow and cost recovery.

The island location also presents unique energy supply and operating risks. With limited on-island energy supply resources (wind and minimal solar) the Company is dependent upon energy sourced off-island via the current and planned submarine cables. Due to recurring off-island transmission constraints the Company is required to have sufficient on-island generating capacity to meet demand. Structured as an integrated generation, transmission and distribution utility, the Company faces challenges maintaining and operating aging generating equipment, sourcing economically priced fuel and retaining a skilled workforce at a facility with a planned retirement in the near term. These factors present additional incremental business risks relative to other utilities.

From a regulatory risk perspective the Company also faces incremental risk relative to other utilities due to the frequency in which the regulatory framework has been changed over the last twenty years. Most recently, the Province introduced legislative amendments to lower the Company's minimum common equity component from 40 per cent to 35 per cent and establishing a maximum allowed common equity of 40 per cent for purposes of setting revenue requirement. The Province also introduced legislation to implement its previously announced policy to have the option to own future generating assets and capacity on PEI. Together these changes have the potential to increase franchise risk and further supports a higher ROE risk premium relative to otherwise comparable Canadian utilities.

Prior to these legislative changes, the most recent S&P Report on Maritime Electric dated March 31, 2015 categorized the Company's financial risk profile as "aggressive" based upon an expectation of low but stable cash flows and a legislated minimum equity base of 40 per cent. As shown in Schedule 12-6 of the Application evidence (page 71), the "aggressive" category assigned by S&P is already one level below that assigned to comparable utilities. Although S&P has not yet updated its assessment of the Company for 2016, the changes to lower the common equity component may contribute to a weakening of the financial risk profile in the future thereby increasing the relative level of risk compared to other utilities.

Based upon these continuing risk factor differences between Maritime Electric and other comparable utilities, it is the Company's view that a risk premium of 25 – 50 basis points is reasonable and justifiable.

A 9.35 per cent ROE is below the target range proposed in the General Rate Application. With the three year certainty of a known ROE target in place, the Company recognizes that regulatory risk has been somewhat mitigated during this period and has, therefore, agreed to an ROE at the lower end of what it considers to be a reasonable outcome.

## RATE OF RETURN

**27. Do you have any information indicating the Schedule of Inputs is now inaccurate , or will within the term of the Agreement, be different than the projections there in any material respects?**

**Response:**

27. The Schedule of Inputs was completed in January 2016 based upon actual results to December 31, 2015 and management's best estimates for the 2016 – 2018 period. The Company is not aware of any information or circumstances that would change the Schedule of Inputs in any material manner.