MARITIME ELECTRIC
A FORTIS COMPANY

April 5, 2019

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The Island Regulatory and Appeals Commission

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

Dear Ms. Mosher:

General Rate Application - Docket UE20944
Response to Interrogatories IR-55 to IR-70 from Multeese Consulting Inc.

Please find attached the Company's responses to IR-55 to IR-70 Interrogatories from Multeese Consulting Inc. with respect to the General Rate Application filed on November 30, 2018.

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

Gloria Crockett, CPA, CA
Manager, Regulatory & Financial Planning

GCC23
Enclosure

INTERROGATORIES

Responses to Additional Interrogatories IR-55 – IR-70
from
Multeese Consulting Inc.

General Rate Application
UE20944

Submitted April 5, 2019

IR-55 MECL states in response to **Multeese IR-3(a)** that "*With the addition of two more submarine cables in 2017, the focus of this criterion has shifted more to transmission constraints in southeastern New Brunswick*". Please elaborate on why constraints in southeastern New Brunswick have become the focus of the N-1 criterion.

Response

Prior to the expansion of the interconnection in 2017, energy imports from the mainland to the Island were limited to a maximum of 200 MW as each of the two original cables is rated for 100 MW. The single worst-case outage for limiting supply to the Island was the loss of one of the two original submarine cables which then limited off-Island imports to 100 MW.

With the additional two submarine cables in place, there is 560 MW of thermal import capacity available – 180 MW for each of the two new cables in addition to 100 MW for each of the original cables. Loss of one of the new cables leaves 380 MW of thermal import capacity.

The NB-NS/PEI interface firm transfer capability is currently limited to 300 MW which is the amount of firm energy that can be supplied across the interface under the worst-case N-1 contingency situation on the mainland. The limiting elements are located on the New Brunswick transmission system. During periods of contingency or system maintenance, the amount of power that can be imported from the mainland to the Island can be less than 300 MW, depending on energy schedules and contingency duration.

PEI's peak system load is 280 MW and is projected to gradually increase in response to increased electrification of space heating and transportation. The Island's peak load is forecast to surpass 300 MW by 2023.

Energy shortfalls from the mainland must be made up by dispatching on-Island back up generation.

IR-56 In response to **Multeese IR-4(d)**, MECL discusses the EPS software and notes that the pricing inputs "*enable the program to economically dispatch the energy products and generation based on pricing at the time*". Please confirm that the order of dispatch provided in part b. of the response is always the economic dispatch. If this is not the case, please discuss the relationship between the order in part b. and the economic dispatch of EPS, including which has dispatch precedence.

Response

In the Multeese IR-4(b) response, the dispatch order indicated is the order during normal operating conditions. The Economic Dispatch Model that is built into the EPS software is used when Maritime Electric has been put on Notice ("Notification Period") by NB Energy Marketing ("NBEM") during abnormal system operating conditions.

Products that have a Notification Period are Secure Energy and Assured Energy, and these are backstopped as indicated in IR-4b (5). During abnormal system operating conditions with the provision of Notification, Secure and Assured Energy can only be interrupted or curtailed after the Notification Period has expired. However, the energy pricing can be increased immediately. The model requires the following inputs for comparison purposes:

- Updated indicative pricing for the Secure Energy and Assured Energy products;
- Indicative energy pricing for energy from another supplier or from NB Energy Marketing (i.e. ISO-New England Market Pricing with the appropriate exit fees and transmission fees through NB to Maritime Electric); and
- Maritime Electric on-Island generation costs based upon updated cost for Bunker and diesel fuel prices.

The model will provide a comparison based on the number of scenarios created and determines the lowest priced option.

IR-57 Further to the response to **Multeese IR-8(p)**, please provide MECL's 2017 costs with respect to the Initial Capital Cost, the Sinking Fund and Capital Additions and explain why they are not included in the OATT. In addition, please identify where these costs are included in the CAS.

Response

Maritime Electric's 2017 costs with respect to the Initial Capital Cost, Sinking Fund and Capital Additions are as follows (Maritime Electric began incurring these costs on March 1, 2017):

Initial Capital Cost - $2,681,281.40 ($268,128.14 per month for 10 months)
Sinking Fund - $269,700 ($26,970 per month for 10 months)
Capital Additions - $0

The monthly Sinking Fund costs are not in addition to the Initial Capital Cost contributions; rather the Sinking Fund costs are included in Maritime Electric's monthly cost contribution towards the Initial Capital Cost. The Sinking Fund is controlled by the Prince Edward Island Energy Corporation ("PEIEC") and the PEIEC directs the appropriate portions of the monthly Initial Capital Cost collections remitted by Maritime Electric and the Summerside utility into the Sinking Fund.

These costs are not included in the OATT because they are not recovered from all transmission system customers. The Government of PEI decided, as a matter of public policy, that the costs for the initial construction and any major subsequent capital additions would be the responsibility of the electric load customers on PEI since the two additional submarine cables were being installed, in the short to medium term, primarily to provide increased capacity to serve Island load. This means that transmission customers whose primary function is to export energy are not responsible to pay for the capital costs associated with the upgraded interconnection.

The Government also decided, as a matter of public policy, that ongoing operating and maintenance costs, capital replacements and New Brunswick OATT charges associated with the interconnection should be shared among all transmission customers and thus included in the OATT, since all transmission customers ultimately benefit from the increased reliability provided by the upgraded interconnection.

These costs were included as part of account 7415, and can be seen in Schedule 6.0 of the Allocation Study.

IR-58 Further to **Multeese IR-9**, please provide a copy of MECL's 2015 Application to the Commission to add another 50MW CT.

Response

The Application and Evidence for the Charlottetown Combustion Turbine 4 Project filed on June 25, 2015 is filed as IR-58 Attachment 1 to this response.

IR-59 Further to **Multeese IR-12**, please provide the coincident and non-coincident Large Industrial peak loads served at each of transmission and distribution voltages.

Response

THIS RESPONSE WILL BE PROVIDED IN A CONFIDENTIAL BASIS UPON RECEIPT OF APPROVAL FROM IRAC.

IR-60 Further to **Multeese IR-12**, please provide the diversity factors applied to General Service and Small Industrial in the calculation of non-coincident peak loads for the class.

Response

In subsequent conversation with the Cost Allocation Study ('CAS') consultant, Maritime Electric has determined that diversity factors were not applied during the development of non-coincident peak (NCP) loads for the General Service and Small Industrial classes. Thus, the paragraph describing their derivation in IR-12 [IR-12 a), subsection "Non-coincident Peak Demands", second paragraph] is incorrect.

The NCP loads for Residential, General Service and Small Industrial were estimated based on the following:

- The annual kWh sales amount for each class;
- Results from a previous Residential and General Service class load study; and
- Billing demands, keeping in mind that some of the smaller General Service customers do not have demand meters (up to the first 20 kW of monthly demand for a General Service customer is not billed)

In addition, the figure for 1CP – Transmission Input for Large Industrial as presented in the table in response IR-12 b) is incorrect. The correct figure should be 16,303 kW, not 16,203 kW as was presented.

IR-61 Further to the response to **Multeese IR-15(j) and (k)**, please identify the following in dollars:

a) Total ECC costs
b) Total ECC costs in Account 7150
c) The amount functionalized to Power Supply
d) The amount functionalized to Transmission
e) The amount functionalized to Distribution
f) The total ECC costs in Account 7510.
g) ECC costs in any account other than 7150 and 7510.

Response

a. All of the Company's costs associated with the operations of the Energy Control Centre totalled $988,340 in 2017 and are captured as either ECC (Account 7150) or OATT (Account 7510) costs.

b. The costs associated with co-ordinating the delivery of energy supply (i.e. distribution) are captured under account 7150 – Energy Control Centre and totalled $763,155 in 2017. These costs are primarily labour driven, as outlined in response to Commission IR-26, based on the actual ECC operators' time as well as related management and supervision in co-ordinating the deliver of energy supply. Other non-labour costs were approximately $15,000 in 2017 and are primarily related to communications costs.

c., d. and e.

The total ECC costs were $988,340 as per IR-61 (a) above, which is comprised of two accounts: 7150 ($763,155) and 7510 ($225,185). The functionalized amounts are as follows:

	Power Supply		**Transmission**		**Distribution**		**Total**
	(%)	**($)**	**(%)**	**($)**	**(%)**	**($)**	**($)**
7150 – ECC Operations	25	$190,789	25	$190,789	50	$381,577	$763,155
7510 - OATT	0	$0	100	$225,185	0	$0	225,185
Total		**$190,789**		**$415,974**		**$381,577**	**$988,340**

f. The ECC costs related to the transmission system and administering the OATT are captured in account 7510 – OATT and totalled $225,185 in 2017. These costs are primarily labour related (approximately $187,000 in 2017) and reflect the actual time of ECC Operators' associated with administering the OATT. As well, approximately $34,000 of the remaining costs in account 7510 relate to licensing services paid to Open Access Technology International ("OATI") for the e-tagging system used for transmission scheduling across New Brunswick and PEI.

g. See response to IR-61(a) above.

IR-62 It is stated in the response to **Multeese IR-15(l)** that Account 7415 captures all operating and maintenance expenses associated with the cables portion of the interconnection, "*including the debt repayment*". Please explain why it is appropriate to combine O&M and debt expenses into one account and classify and allocate them on a common basis.

Response

The main reason is that from Maritime Electric's perspective the annual amount of the "debt repayment" would be more correctly described as "the annual submarine cables rental or lease expense". The PEI Energy Corporation ("PEIEC") is the owner of the submarine cables and Maritime Electric leases them from the PEIEC. For the PEIEC, as owner, debt repayment is a more appropriate description as the lease or rental payments by Maritime Electric to the PEIEC recover the capital and financing costs for the project.

IR-63 Further to the response to **Multeese IR-32**:

a) Please clarify which units have provided (or are expected to provide) Assured Energy backup in each of the summer and winter periods from April 1, 2017 – March 31, 2022.

b) Please explain what is meant by the statement that "*NBEM agreed to backstop the CTGS during the Summer Period*". What capacity is NBEM supplying to provide this backstop, and at what cost?

c) Where are the costs of b) included in MECL's revenue requirement?

Response

a. **Winter Period**

In past Energy Purchase Agreements (EPA), NB Energy Marketing has provided generating capacity during the first 48 hours (December and January), or first 96 hours (November, February and March) during the Winter Period for backstopping the Assured Energy product. NB Energy Marketing has continued this arrangement with the new EPA (March 1, 2019 – February 29, 2024).

Maritime Electric's Borden Generating Station (40 MW of combustion turbines) will provide generating capacity to backstop the Assured Energy for the remainder of the 90 day Notification Period. Maritime Electric's Charlottetown Thermal Generating Station units will backstop the Assured Energy product from Day 91 onwards.

Summer Period

During the Summer Period (April 1 – October 31), NB Energy Marketing will provide generating capacity during the 90 days of the Notification Period for backstopping the Assured Energy product. Maritime Electric's Charlottetown Thermal Generating Station units will provide the generating capacity to backstop the Assured Energy product from Day 91 onwards.

b. As indicated under response (a) "Summer Period" NB Energy Marketing will provide generating capacity during the 90 days of the Notification Period for the Assured Energy product. Maritime Electric does not know what generating units are providing this capacity on behalf of NB Energy Marketing. The cost of supplying this capacity is built into the Assured Energy pricing.

c. These costs are Included as part of the Energy Purchase Agreement System Energy Purchases in Maritime Electric's revenue requirement (see Schedule 8-4 in the General Rate Application).

IR-64 Further to the response to **Multeese IR-40**:

a) Please confirm that the data provided includes seasonal customers.
b) Please provide the number of customers whose average annual consumption falls within the following ranges: 2001 – 3000 kWh, 3001 - 4000 kWh, 4001 – 5000 kWh, 5001 – 10,000 kWh, and 10,001 or more.

Response

a. In response IR-40, the customer counts provided do not include seasonal customers. The customer count, with seasonal customers included, whose average monthly consumption falls in the range categories indicated in IR-40 is provided in response b. below.

b. The following table shows the number of residential customers, including seasonal customers, whose average monthly consumption falls in the range categories indicated in the original IR-40 as well as the additional categories shown above.

Monthly Average Consumption Range	Customer Count
1 - 200 kWh	9,605
201 - 400 kWh	13,127
401 - 500 kWh	6,672
501 - 600 kWh	6,445
601 - 700 kWh	5,582
701 - 800 kWh	4,685
801 - 900 kWh	3,807
901 - 1000 kWh	2,932
1001 - 1200 kwh	4,459
1201 - 1500 KWh	4,207
1501 - 2000 kWh	3,140
2001 - 3000 kWh	1,594
3001 - 4000 kWh	345
4001 - 5000 kWh	165
5000 - 10000 kWh	231
More than 10000 kWh	84
Grand Total	**67,080**

IR-65 With respect to the response to **Multeese IR-46**, please explain the asterisks on Transmission and General and Administrative.

Response

The response to Multeese IR-46 references Schedule 14-2 in Section 14.4, page 151 of the General Rate Application.

The asterisks on the Transmission and General Administrative expenses are described directly below Schedule 14-2 and are as follows:

* Includes OATT Expenses
** Excludes Fortis Inc. Administrative Charges

IR-66 The tables provided in response to **Multeese IR-50** show Basic Energy Charges per kWh of $0.1438 for 2019, $0.1476 for 2020 and $0.1499 for 2021. Please provide the derivation of those numbers.

Response

The General Rate Application ("GRA") contains detailed evidence in support of the Company's revenue requirement for 2019-2021 as set out in Schedule 14-4 of the Application and seeks to establish customer electricity rates that are designed to recover the forecast revenue requirement from the various rate classes. The proposed recovery of 2019-2021 revenue requirement from the various rate classes is achieved through service charges, demand charges where applicable, and basic energy usage charges.

The Company's experience from the five year PEI Energy Accord (March 1, 2011 – February 29, 2016) indicates that customers prefer the rate stability and predictability derived from multi-year rate setting periods. In addition, in establishing customer electricity rates for the period March 1, 2016 to February 28, 2019, IRAC confirmed its support of this approach in Order UE16-04R, paragraph 53 wherein the Commission stated:

> *The Commission encourages multi-year rate setting, whenever possible, so as to allow for stable and predictable electricity rates for customers…*

The basis of the proposals contained in the GRA are designed to achieve an annual increase in electricity costs of 1.1 per cent per year for each of the next three years for the typical customer in each of the Company's rate classes. The proposed rates set out in Schedule 15-1 of the GRA reflect this approach to establishing customer rates which provides stable and predictable adjustments to the annual cost of electricity for customers.

With respect to the energy charges in Schedule 15-1, there are a number of components that make up the per kWh rates. The components include the Basic Energy Charge which recovers the Company's revenue requirement as well as fixed rates of recovery or refund for deferral amounts related to ECAM, Provincial Costs Recoverable, the Cable Contingency Fund, the Provincial Energy Efficiency Program and RORA.

The derivation of the percentage changes to the Basic Energy Charge rate for a specific class is a function of all these components. In setting the Basic Energy Charge for each class of customer, the Company adjusts basic rates to allow the Company to recover the forecast overall revenue requirement including service charges, demand charges and energy charges while keeping percentage increase in the total annual cost, before tax, for a typical customer in each class at 1.1 per cent.

The following tables show the composition of the various components of the total energy charge per kWh for each rate class presented in Schedule 15-1 of the GRA:

Energy Charge per kWh – Revenue Requirement (A)						
	2016	2017	2018	2019	2020	2021
Residential - First Block	$ 0.132000	$ 0.137500	$ 0.140900	$ 0.143800	$ 0.147600	$ 0.149900
Residential - Second Block	$ 0.104300	$ 0.108700	$ 0.111400	$ 0.113700	$ 0.116700	$ 0.118500
General Service - First Block	$ 0.162800	$ 0.169600	$ 0.173900	$ 0.177500	$ 0.182100	$ 0.184800
General Service - Second Block	$ 0.105400	$ 0.109800	$ 0.112600	$ 0.114900	$ 0.117900	$ 0.119700
Small Industrial - First Block	$ 0.159400	$ 0.166100	$ 0.170300	$ 0.173800	$ 0.178300	$ 0.181000
Small Industrial - Second Block	$ 0.790000	$ 0.082300	$ 0.084400	$ 0.086100	$ 0.088300	$ 0.089600
Large Industrial	$ 0.063900	$ 0.067300	$ 0.068600	$ 0.070500	$ 0.073200	$ 0.074400

Energy Charge per kWh - Other Amounts (B)						
	2016	2017	2018	2019	2020	2021
ECAM	$ 0.002058	$ 0.001188	$ 0.000575	$ 0.003643	$ 0.001784	$ 0.001475
Provincial Costs Recoverable	$ 0.005360	$ 0.005360	$ 0.005360	$ -	$ -	$ -
Provincial Energy Efficiency Program	$ -	$ -	$ -	$ 0.000700	$ 0.000800	$ 0.000900
Cable Contingency Fund	$ 0.000270	$ 0.000270	$ 0.000270	$ -	$ -	$ -
RORA	$ (0.004097)	$ (0.004732)	$ (0.003445)	$ (0.002504)	$ (0.002504)	$ (0.002504)
Subtotal per kWh	$ 0.003600	$ 0.002100	$ 0.002800	$ 0.001800	$ 0.000100	$ (0.000100)

Total Energy Charge per kWh per Schedule 15-1 (A + B)						
	2016	2017	2018	2019	2020	2021
Residential - First Block	$ 0.135600	$ 0.139600	$ 0.143700	$ 0.145600	$ 0.147700	$ 0.149800
Residential - Second Block	$ 0.107900	$ 0.110800	$ 0.114200	$ 0.115500	$ 0.116800	$ 0.118400
General Service - First Block	$ 0.166400	$ 0.171700	$ 0.176700	$ 0.179300	$ 0.182200	$ 0.184700
General Service - Second Block	$ 0.109000	$ 0.111900	$ 0.115400	$ 0.116700	$ 0.118000	$ 0.119600
Small Industrial - First Block	$ 0.163000	$ 0.168200	$ 0.173100	$ 0.175600	$ 0.178400	$ 0.180900
Small Industrial - Second Block	$ 0.793600	$ 0.084400	$ 0.087200	$ 0.087900	$ 0.088400	$ 0.089500
Large Industrial	$ 0.067500	$ 0.069400	$ 0.071400	$ 0.072300	$ 0.073300	$ 0.074300

The Basic Energy Charge per kWh provided in response to Multeese IR-50 represents the per kWh rate to recover the revenue requirement component which, together with the other components of a customer's bill outlined above, yields an annual 1.1 per cent increase for the typical Residential Customer. It is derived by taking the current first block residential basic rate per kWh of $0.1409 per kWh approved by Commission Order UE16-04 and applying annual rate increases of 2.05 per cent in 2019, 2.65 per cent in 2020 and 1.55 per cent in 2021. This is illustrated in the Company's response to Multeese IR-50 and results in the projected 1.1 per cent annual increase for the typical Residential Customer in each year as shown in Schedules 15-2 and 15-3 of the GRA.

IR-67 Further to the response to **Multeese IR-53**, please provide the Excel files supporting this response.

Response

As requested, the excel file supporting the response to Multeese IR-53 is provided in the following file:

- Multeese IR-67 - Excel file for Multeese IR-53.xlsx

IR-68 **Schedule 14-6** shows electric revenue at existing rates and **Schedule 14-7** shows electric revenue at the rates being proposed by MECL. Please confirm that the only differences in the calculation of electric revenue between these two schedules for the years 2019 – 2021 are differences in the rates being applied and the increase of the Residential second block from 2000 kWh per month to 5000 kWh per month beginning March 1, 2021. If this is not the case, please identify all other differences.

Response

The original Schedule 14-6 of the Application does not correctly reflect the revenue derived from existing basic rates. The Company has filed an amended Schedule 14-6 with the Commission. In addition, an updated response to Multeese IR-48 has been provided. The updated Schedule 14-6 is provide below:

SCHEDULE 14-6						
Energy Sales by Class (Existing Basic Rates)						
	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Energy by Class - (GWh)						
Residential	563.5	577.0	598.9	620.7	647.5	667.0
General Service I	386.8	384.9	385.3	389.7	392.0	392.3
Large Industrial	129.9	133.6	149.7	154.7	159.2	160.0
Small Industrial	100.1	104.6	93.3	94.4	95.0	95.0
Street Lighting	5.8	4.5	3.3	2.1	0.7	(0.4)
Unmetered	2.4	3.4	4.4	5.4	6.4	7.4
Total Energy Sales	**1,188.4**	**1,208.0**	**1,234.9**	**1,267.0**	**1,300.8**	**1,321.3**
Gross Revenue by Class - ($)						
Residential	$92,562,937	$96,868,216	$102,301,800	$106,113,800	$110,140,700	$113,154,700
General Service I	59,016,156	60,498,583	62,207,800	63,209,600	63,592,800	63,681,200
Large Industrial	10,786,613	11,481,970	13,500,900	13,778,600	14,087,300	14,141,900
Small Industrial	12,968,350	13,640,807	12,638,200	12,784,200	12,856,400	12,867,300
Street Lighting	2,420,167	2,424,681	2,414,800	2,305,800	2,195,400	2,085,000
Unmetered	403,098	412,465	419,800	409,100	410,100	411,100
Total Gross Electric Revenue	**178,157,321**	**185,326,722**	**193,483,300**	**198,601,100**	**203,282,700**	**206,341,200**
Rate of Return Adjustment	(2,100,000)	(2,767,885)	(3,952,400)	-	-	-
Weather Normalization Adjustment	126,031	52,155	161,800	-	-	-
Total Electric Revenue	**176,183,352**	**182,610,992**	**189,692,700**	**198,601,100**	**203,282,700**	**206,341,200**
Total Other Revenue	**10,154,053**	**9,924,289**	**11,136,200**	**12,161,000**	**12,324,900**	**12,451,600**
Total Revenue	**$186,337,405**	**$192,535,281**	**$200,828,900**	**$210,762,100**	**$215,607,600**	**$218,792,800**

The only differences in this updated Schedule 14-6 and Schedule 14-7 are the proposed rate changes set out in the Application, including the change to the Residential service charge on March 1, 2019, and the increase in the Residential second block from 2,000 kWh to 5,000 kWh per month beginning on March 1, 2021.

IR-69 Comparing the **Schedule 14-7** class revenues for 2021 to the **Schedule 14-6** class revenues for 2021 suggests the following cumulative rate increases by class over the three years 2019, 2020 and 2021: Residential - 3.6%, GS – 4.8%, Small Industrial – 4.7%, Large Industrial - 6%, Street Lighting – 5.5% and Unmetered – 5.8%. These compare to a total electric revenue increase of 4.25%.

a) Please confirm that these rate increases are an accurate reflection of what is proposed by the Company.
b) If a) cannot be confirmed, please explain why not, and provide the cumulative rate increases being proposed by class.
c) Please reconcile the numbers from a) or b) with the Company's statements in Section 15 that its proposed rate increase is 1.1% per year for all classes.
d) If a) is confirmed, please comment on why the Residential class (which has an R/C of approximately 91%) is proposed to have a cumulative rate increase less than the system average, while the GS class (which has an R/C of approximately 121%) is proposed to have a cumulative rate increase greater than the system average.

Response

a. The percentages provided in IR-69 is a reflection of the change in total electric revenue divided by kWh sales by rate class. This is not a true reflection of the cumulative per kWh energy usage rate increase by class over the three year period as proposed in Schedule 15-1. The proposed recovery of the annual revenue requirement for 2019-2021 from the various rate classes is achieved through service charges, demand charges and energy usage charges. These amounts, as summarized in Schedule 14-7, reflect forecast customer growth, demand and energy sales levels in each of the rate classes as well as the rate design recommendations proposed in the Application to increase the residential second block in 2021. Each customer class has different consumption levels, rates and rate structures such as service charges, demand charges and energy usage charges that ultimately comprise the total contribution from each rate class to revenue requirement.

b. In addition to the recovery of the annual revenue requirement, the Application also details the recovery or refund of other amounts such as ECAM, Provincial Costs Recoverable, Cable Contingency Fund, Provincial Energy Efficiency Program and RORA included in the energy usage charges for each class set out in Schedule 15-1.

The following tables show the composition of the various components of the total energy charge per kWh for each rate class proposed in Schedule 15-1:

Energy Charge per kWh – Revenue Requirement (A)							
	2016	2017	2018	2019	2020	2021	Cumulative Change over 2018 Rates
Residential - First Block	$ 0.132000	$ 0.137500	$ 0.140900	$ 0.143800	$ 0.147600	$ 0.149900	6.4%
Residential - Second Block	$ 0.104300	$ 0.108700	$ 0.111400	$ 0.113700	$ 0.116700	$ 0.118500	6.4%
General Service - First Block	$ 0.162800	$ 0.169600	$ 0.173900	$ 0.177500	$ 0.182100	$ 0.184800	6.3%
General Service - Second Block	$ 0.105400	$ 0.109800	$ 0.112600	$ 0.114900	$ 0.117900	$ 0.119700	6.3%
Small Industrial - First Block	$ 0.159400	$ 0.166100	$ 0.170300	$ 0.173800	$ 0.178300	$ 0.181000	6.3%
Small Industrial - Second Block	$ 0.790000	$ 0.082300	$ 0.084400	$ 0.086100	$ 0.088300	$ 0.089600	6.2%
Large Industrial	$ 0.063900	$ 0.067300	$ 0.068600	$ 0.070500	$ 0.073200	$ 0.074400	8.5%

Energy Charge per kWh - Other Amounts (B)							
	2016	2017	2018	2019	2020	2021	Cumulative Change over 2018 Rates
ECAM	$ 0.002058	$ 0.001188	$ 0.000575	$ 0.003643	$ 0.001784	$ 0.001475	156.5%
Provincial Costs Recoverable	$ 0.005360	$ 0.005360	$ 0.005360	$ -	$ -	$ -	-100.0%
Provincial Energy Efficiency Program	$ -	$ -	$ -	$ 0.000700	$ 0.000800	$ 0.000900	100.0%
Cable Contingency Fund	$ 0.000270	$ 0.000270	$ 0.000270	$ -	$ -	$ -	-100.0%
RORA	$ (0.004097)	$ (0.004732)	$ (0.003445)	$ (0.002504)	$ (0.002504)	$ (0.002504)	-27.3%
Subtotal per kWh	**$ 0.003600**	**$ 0.002100**	**$ 0.002800**	**$ 0.001800**	**$ 0.000100**	**$ (0.000100)**	**-103.6%**

Total Energy Charge per kWh per Schedule 15-1 (A + B)							
	2016	2017	2018	2019	2020	2021	Cumulative Change over 2018 Rates
Residential - First Block	$ 0.135600	$ 0.139600	$ 0.143700	$ 0.145600	$ 0.147700	$ 0.149800	4.2%
Residential - Second Block	$ 0.107900	$ 0.110800	$ 0.114200	$ 0.115500	$ 0.116800	$ 0.118400	3.7%
General Service - First Block	$ 0.166400	$ 0.171700	$ 0.176700	$ 0.179300	$ 0.182200	$ 0.184700	4.5%
General Service - Second Block	$ 0.109000	$ 0.111900	$ 0.115400	$ 0.116700	$ 0.118000	$ 0.119600	3.6%
Small Industrial - First Block	$ 0.163000	$ 0.168200	$ 0.173100	$ 0.175600	$ 0.178400	$ 0.180900	4.5%
Small Industrial - Second Block	$ 0.793600	$ 0.084400	$ 0.087200	$ 0.087900	$ 0.088400	$ 0.089500	2.6%
Large Industrial	$ 0.067500	$ 0.069400	$ 0.071400	$ 0.072300	$ 0.073300	$ 0.074300	4.1%

c. As discussed in Section 3.3 and Section 15 of the General Rate Application, the Company is proposing a general rate adjustment including all of the components discussed in response IR-69 (b) above, that will result in an annual increase in electricity costs (before taxes) of 1.1 per cent in each of the next three years for a typical customer in the Residential, General Service, Industrial and other rate classes.

Schedule 15-2 provides the breakdown of the various components of the annual cost for a typical rural Residential customer consuming 650 kWh per month or 7,800 kWh per year based on the proposals outlined in the Application. Schedule 15-3 provides the same information for a typical Urban Residential customer and Schedule 15-4 for a typical General Service Customer. The table below is a Summary of the annual cost before tax for a typical customer in each these three classes and the percentage change to the annual cost before tax.

Typical Customer Total Annual Cost before Tax					
Rate Class	**GRA Reference**	**2018**	**2019**	**2020**	**2021**
Residential Rural	Schedule 15-2	$ 1,443.59	$ 1,430.83	$ 1,446.75	$ 1,463.06
% Change			-0.9%	1.1%	1.1%
Residential Urban	Schedule 15-3	$ 1,415.39	$ 1,430.83	$ 1,446.75	$ 1,463.06
% Change			1.1%	1.1%	1.1%
General Service	Schedule 15-4	$ 22,650.82	$ 22,894.38	$ 23,139.29	$ 23,384.22
% Change			1.1%	1.1%	1.1%

As discussed in Section 15.2 of the GRA, the proposed reduction of the rural residential service charge to that of the urban service charge will result in a one-time overall reduction the annual cost for a typical rural residential customer in 2019 (0.9%).

Further information on the individual components of the annual costs presented in Schedules 15-2, 15-3, and 15-4 were provided in response to Multeese IR-50, IR-51 and IR-52.

d. As shown in our response (b) above, the cumulative change to the basic revenue charge for the three year period for General Service Customers (6.3%) is actually slightly less than that of Residential Customers (6.4%).

In the General Rate Application Section 13.4.2, the Company acknowledges that the RTC of 122 per cent for the General Service rate class is outside the proposed target of 90 to 110 per cent RTC range. The Application also states that in order to develop recommendations and a course of action that will transition this rate class toward the target RTC range, further load and consumption data analysis needs to be completed by the Company.

In response to Commission Staff IR-54, included with this response as IR-69 – Attachment 1, the Company discusses its rationale for conducting further study of the Residential and General Service rate classes prior to implementing further rate design changes.

IR-70 Comparing the 2021 Large Industrial Revenue in **Schedule 14-7** to the 2021 Large Industrial Revenue in **Schedule 14-6** suggests a cumulative rate increase of approximately 6% over the three years 2019 – 2021. However, the energy charges shown for Large Industrial for 2021 in Schedule 15-1 are only 4.1% higher than the energy charges in 2018. Please explain why the Large Industrial revenue increase is higher than the increase in energy rates, when it should be lower, given no change to the Large Industrial Demand Charge.

Response

As discussed in response IR-69, the total energy charge per kWh in Schedule 15-1 of the GRA is comprised of a Basic Energy Charge to recover the Company's revenue requirement as well as a number of other components related to costs recovered or refunded on behalf of the PEI Energy Corporation and regulatory deferrals such as ECAM, Provincial Costs Recoverable, Provincial Energy Efficiency Program, Cable Contingency Fund and RORA. For the Large Industrial Rate Class, the total energy charge per kWh is, in relative terms, lower than that of the other customer classes and as such, changes to these other components in rates have a larger impact on the overall rate for this class.

In order to achieve the overall 1.1 per cent increase in annual costs for a typical large industrial customer, the reductions in the per kWh rates for other amounts as outlined in IR-69(b) results in a larger increase to the per kWh energy charge related to revenue requirement for the large industrial class. The combined outcome is a cumulative 4.1 per cent change in the total per kWh rate for a large industrial customer as shown the IR-69(b).

INTERROGATORIES

Section IR-69

ATTACHMENT

IR-54 The revenue to cost ratio for the General Service rate class is currently 122. Please explain why the current application does not rectify this issue, and provide justification for the continuation of a revenue to cost ratio of 122 for General Service customers.

Response

Maritime Electric operates under a traditional cost of service regulatory model. Under cost of service regulation, the utility's rates are intended to recover the cost of proving electricity service to customers. To enable an assessment of the fairness of the rates charged to each of the customer classes, Maritime Electric periodically does a cost allocation study. The results of a cost allocation study also provide a benchmark to guide rate design.

The basic approach followed in a cost allocation study is to first separate the utility's costs by function, and then break down the costs for each function into the following three categories:

- Demand costs – these are costs that vary as a function of the maximum load (coincident peak) that the Company is required to serve during a year. The amount of generating capacity that must be installed or purchased is an example. Demand costs for the distribution system can also be driven by non-coincident peak loads; e.g. when the peak load for a given customer class occurs at a different time than the time of the annual system peak load.
- Energy costs – these are costs that vary as a function of the total amount of electricity supplied by the Company during the course of a year. Generation fuel is an example.
- Customer costs – these are costs that vary as a function of the number of customers that the Company serves. Meter reading is an example.

The final step is to allocate to each customer class their appropriate share of each of the above three types of costs. For Energy costs and Customer costs this is relatively straightforward because the number of kWh used by each customer class and the number of customers in each customer class are known quantities.

However, allocating the Demand costs is not straightforward because for some of the customer classes, either the maximum load or the class load at the time of system peak for some of the customer classes is not known and cannot be measured directly. This is the case for the Residential customer class, and small General Service customers' classes which together represent approximately 80% of Maritime Electric's load. The allocation of Demand costs to these customer classes relies on estimates of their peak loads. These estimates are based in part on load research done in the early 1990s. That research involved collecting hourly load data for a representative sample of Residential and General Service customers that was then used to improve the estimates of coincident and non-coincident peak loads for those customer classes in subsequent cost allocation studies.

As stated in Section 13.4.2 of the application, the Company has expanded its 2018 Bridge Meter Project in its 2019 Capital Budget Application to conduct a load research study for Residential and General Service customers. The Company will collect hourly load data for a sample of Residential and General Service customers beginning in 2019 and continuing through 2020. The results of this load study will form the basis of the next Cost Allocation Study expected to be conducted in 2021. The study will provide a more accurate allocation of load between residential and general service customers which will in turn impact the allocation of demand costs and resulting RTCs of both of these classes. This is one reason the Company did not propose rate design changes for the General Service Class at this time.

Another reason is the uncertainty with regard to determining the appropriate rate classification for farms. The Company is currently gathering and analyzing load and consumption data for farms included in the residential rate class that will provide information necessary to ensure farms customers are classified in the appropriate rate class. The results of this study may conclude that some of these farms should be classified as general service or small industrial which would impact the cost and revenue allocations to these classes as well as the resulting RTCs. Using data from Schedule 1.0 of the Chymko 2017 Cost Allocation Study, the table below shows for illustration purposes that the Revenue to Cost ratio for the General Service rate class would decrease from 121% without Farms to 116% with Farms.

Effect of Combining Farms with Small Industrial			
	Farm	**General Service**	**Farm + General Service**
Base Revenue ($ x 1,000)	6,868	58,151	65,019
Allocated Cost ($ x 1,000)	8,732	47,880	56,252
Revenue to Cost Ratio (%)	82	121	116

Using data from Schedule 1.0 of the Chymko 2017 Cost Allocation Study, the table below shows that the Revenue to Cost ratio for the Small Industrial rate class would decrease from 102% to 94% with Farms included.

Effect of Combining Farms with Small Industrial			
	Farm	**Small Industrial**	**Farm + Small Industrial**
Base Revenue ($ x 1,000)	6,868	11,675	18,543
Allocated Cost ($ x 1,000)	8,732	11,402	19,774
Revenue to Cost Ratio (%)	82	102	94

The Company believes it is prudent to consider the impact of both the load study and the farm study on cost allocation and RTCs for all classes prior to making recommendations regarding rate design for the General Service class.