MARITIME ELECTRIC
A FORTIS COMPANY

February 1, 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 from Multeese Consulting Inc.

Please find attached the Company's response to 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

GCC03
Enclosure

<u>IR's 1- 14 are General Questions</u>

IR-1 Please describe how system planning, including both supply and delivery of electricity, is conducted for PEI.

a) Who has primary responsibility for the planning?

b) What is the role of each on-island utility with respect to system planning?

c) What is the role of government (as represented by the PEI Energy Corporation) with respect to system planning?

d) What role, if any, does NB Power play with respect to system planning?

e) What software is used in the generation planning process?

<u>Response</u>

a. There are two electric utilities – Maritime Electric Company, Limited ("MECL") and the City of Summerside (the "City" or "Summerside") – that supply end-use electricity customers on PEI. Each is responsible for planning and sourcing its own energy, generation and ancillary services supplies. Each is also responsible for planning its own distribution system.

MECL has primary responsibility for transmission system planning for PEI.

b. MECL has primary responsibility for transmission system planning for PEI. The City is consulted on transmission system planning through the Transmission Users Group, whose terms are specified in MECL's Open Access Transmission Tariff ("OATT") as approved by the Island Regulatory and Appeals Commission (the "Commission").

c. The Prince Edward Island Energy Corporation ("Energy Corporation"), a Crown corporation of the Province of PEI, has attained standing as a 'public utility' under the *Electric Power Act* but does not supply end-use customers. It provides wind generation energy to MECL under long-term PPA contracts, and delivers demand side management and energy efficiency services to the Island on behalf of the Province of PEI.

The Energy Corporation does not have official standing as a member of the Transmission Users Group, however is consulted and informed by MECL in transmission system planning matters.

d. NB Power does not play any direct role with respect to system planning on PEI. One of its subsidiaries - NB Energy Marketing – is currently a member of the Transmission Users Group based on contractual arrangements with the West Cape Wind Farm.

NB Power indirectly plays a role in system planning through its function as the Reliability Coordinator for the Maritimes Region, and through the Interconnection Agreement between MECL and NB Power. The Interconnection Agreement sets out the main planning criteria that MECL follows in planning for supply of generating capacity. See IR-3 (a) for an explanation of these criteria.

e. MECL does not use any specialized software in the generation planning process. MECL on-Island generation is used for backup and emergency supply, and is not used for baseload supply. Its economics are based primarily on avoided cost of capacity and deferral of transmission system upgrades.

IR-2 When did PEI last need to add new supply in order to reliably serve its load, and what new supply (either new generation or new purchase agreement) was added? Please provide any supporting studies which provide the basis on which the new supply determined to be the best solution.

Response

THIS RESPONSE WILL BE PROVIDED ON A CONFIDENTIAL BASIS UPON RECEIPT OF AN EXECUTED NON-DISCLOSURE AGREEMENT.

IR-3 With respect to reliability:

a) What are the planning criteria for PEI in terms of required reserve margin, Loss of Load Probability or Loss of Energy Expectation, and on what basis were they determined?

b) Are the reliability criteria established for PEI as a stand-alone area, or as part of the NB system?

c) When were the most recent reliability studies done for PEI?

d) If the most recent reliability study was done within the last five years, please provide a copy of the study.

<u>Response</u>

a. The main planning criteria for PEI were established in 1977 when the first two submarine cables were installed under the Northumberland Strait and PEI was interconnected with New Brunswick for the first time. These planning criteria formed part of the Interconnection Agreement between NB Power and MECL. (In 1977, MECL supplied all of the PEI electricity load, including service to the Summerside as a wholesale customer.)

The planning criteria are:

1. MECL is required to maintain a planning reserve equal to at least 15% of firm peak load.
2. The maximum amount of capacity from any one source of generation that can be relied on in meeting the planning reserve criterion is limited to 30% of firm peak load.

In the past, with just the two submarine cables installed in 1977, MECL also based its planning on the requirement to have enough generating capacity in PEI so as to be able to meet the annual peak load with one of the submarine cables out of service (the N-1 criterion, widely accepted by the utility industry). 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.

b. The reliability criteria described in the response to a) are for PEI on a stand alone basis but within the context of being interconnected with New Brunswick.

For the purposes of reliability studies, Nova Scotia, New Brunswick, PEI and northern Maine form the Maritimes Area which is one of the Areas within the Northeast Power Coordinating Council (NPCC) Region. Either NS Power or NB Power take the lead in doing the Assessment of Resource Adequacy (the reliability study in regard to generating capacity) for the Maritimes Area as a whole as part of the reporting requirements for the Maritimes Area to NPCC.

c. The most recent Assessment of Resource Adequacy for the Maritimes Area was completed by NB Power in 2018.

d. This study is attached as IR-3 – Attachment 1.

IR-4 With respect to system operations:

a) Who has primary responsibility for the operation of the PEI system on a daily basis?

b) Please describe the basis on which PEI's supply resources (generation or purchases) are dispatched on a daily basis?

c) How are system operations co-ordinated with NB Power?

d) What software is used for system dispatch?

Response

a. The MECL Energy Control Centre (ECC) has the primary responsibility for the operation of the PEI system on a daily basis.

b. PEI's supply resources (generation and/or purchases) are dispatched in the following order:

1. Point Lepreau (capacity-backed) energy of 29 MWh/h;
2. MECL-contracted wind energy up to 92.56 MWh/h;
3. Firm Energy (capacity-backed by NBEM) up to 70 MWh/h;
4. Secure Energy (capacity-backed by Combustion Turbine 3) up to 50 MWh/h; and
5. Assured Energy up to 50 MWh/h (55 MWh/h prior to January 1, 2019). Assured Energy is capacity-backed by:
   - Summer Period – during the Summer Period the Assured Energy product is capacity backed under contract with NB Energy Marketing (NBEM) during the first 90 days of the Notification Period then backed by the Charlottetown Thermal Generating Station (CTGS) if the event continues beyond the 90 days.
   - Winter Period - during the Winter Period the Assured Energy product is capacity backed by the Borden Generating Station (BGS) during the first 90 days of the Notification Period and then by the CTGS if the event continues beyond the 90 days. During the "Winter Period" Maritime Electric will have to purchase 10 Minute & 30 Minute Supplementary Non-Spinning Reserve from the NBP-SO.

c. System operations are coordinated with New Brunswick Power either verbally or via email, according to the following:

- Verbally - System Operator-to-System Operator via a direct phone line for actions such as:

    - Opening and closing-in reactors;
    - Voltage adjustments (NB);
    - Interface limitations due to transmission/generation outages;
    - 10 Minute Reserve and 30 Minute Reserve dispatch; and
    - Emergency Energy transactions, etc.

  - Email - Short Term Operating Procedures (STOPs) are initially sent by the NB Outage Coordinator(s) via email to the MECL Outage Coordinator, and when required a phone call to review the more detailed outages and duration. The Outage Coordinator informs the Transmission Users of the Limitation. The Outage Coordinator then sends the STOP to the System Operations Desk.

d. The Energy Purchase System (EPS) software was developed in-house in 2003/2004 in order to provide a consistent approach in creating Day Ahead Energy schedules by using historical information. The program allows the input of pricing of the energy products under contract as well as the pricing of MECL-owned generation. This enables the program to economically dispatch the energy products and generation based on pricing at the time.

   During the dispatch day the energy schedules are updated as required to minimize the requirement of Energy Imbalance energy purchases. In cases where MECL's on-island generation is dispatched for limitations, Hold to Schedules, or other system requirements, energy purchases are automatically reduced the same amount to match the hourly energy transaction to MECL. Any reserve dispatch or emergency transaction is directed by the NB Power System Operator to the MECL System Operator.

IR-5 Please describe each generating unit on PEI, by supplying for each unit the following information:

a) Who owns the unit?

b) When was the unit built?

c) Please provide details of any major refurbishments of the unit since it was built, including the dates and costs of such refurbishments.

d) What type of unit is it (steam, combustion turbine, wind, etc.)?

e) What is the nameplate capacity of the unit?

f) If the unit uses a fuel, please specify the fuel used.

g) If the unit uses a fuel, what is the annual average heat rate of the unit?

h) What is the firm capacity of the unit used for capacity planning purposes?

i) What was the average annual capacity factor of the unit over each of the last five years?

Response

a. Table 1 below lists the MECL-owned generating units currently in-service on PEI.

Table 1 MECL Thermal Generation					
Unit Number	**Year Installed**	**Nominal Rating**	**Fuel Used**	**Heat Rate[1] (BTU/kWh)**	**Turbine Manufacturer/Make**
Steam Turbine 7[2]	1956	7.5 MW[3]	Bunker C	15,999	Brown-Boveri
Steam Turbine 8	1960	10 MW	Bunker C	13,531	C.A. Parsons
Steam Turbine 9	1963	20 MW	Bunker C	12,364	Associated Electrical Industries
Steam Turbine 10	1968	20 MW	Bunker C	11,709	Associated Electrical Industries
Combustion Turbine 1	1971	15 MW	ULSD[4]	11,579	Rolls-Royce Avon 1533-75L
Combustion Turbine 2	1973	25 MW	ULSD[4]	12,544	General Electric MS5001 Series N
Combustion Turbine 3	2005	50 MW	ULSD[4]	8,523	General Electric LM6000PC

1 Because of low hours of operation, heat rates shown are from efficiency testing.
2 Turbine 7 is no longer counted as Generating Capacity under the Energy Purchase Agreement with NB Energy Marketing as of January 1, 2019.
3 CTGS only has enough boiler steam capacity to obtain 5 MW out of Turbine 7 when all other units are operating.
4 ULSD refers to Ultra Low Sulphur Diesel

There are a number of wind farms on Prince Edward Island as follows:

West Cape Wind Farm
Owner: ENGIE North America
Capacity: 99 MW
Units: 55 x 1.8 MW Vestas V-80 Wind Turbines

East Point Wind Farm
Owner: PEI Energy Corporation
Capacity: 30 MW
Units: 10 x 3 MW Vestas V-90 Wind Turbines

Hermanville - Clearspring Wind Farm
Owner: PEI Energy Corporation
Capacity: 30 MW
Units: 10 x 3 MW Acciona AC 3.0-116 Wind Turbines

Summerside Wind Farm
Owner: Summerside Electric Utility
Capacity: 12 MW
Units: 4 x 3 MW Vestas V-90 Wind Turbines

North Cape Wind Farm
Owner: PEI Energy Corporation
Capacity: 10.56 MW
Units: 16 x 0.66 MW Vestas V-47 Wind Turbines

WEICAN R&D Park Wind Farm
Owner: Wind Energy Institute of Canada (WEICAN)
Capacity: 10 MW
Units: 5 x 2 MW DeWind D9.2 Wind Turbines

ENGIE Norway Wind Farm
Owner: ENGIE North America
Capacity: 9 MW
Units: 3 x 3 MW Vestas V-90 Wind Turbine

Aeolus Norway Wind Farm
Owner: PEI Energy Corporation
Capacity: 3 MW
Units: 1 x 3 MW Vestas V-90 Wind Turbine

Total Installed Wind Turbine Capacity = 203.56 MW

There are also a number of smaller distribution-connected wind and solar installations owned by private households and farms.

Summerside also owns a number of smaller diesel generator units. Table 2 below lists the thermal generating units owned by Summerside and currently in-service on Prince Edward Island:

Table 2 Summerside Thermal Generation					
Unit Number	**Year Installed**	**Nominal Rating**	**Fuel Used**	**Annual Average Heat Rate (BTU/kWh)**	**Turbine Manufacturer/Make**
COS Thermal Unit 1	1960	2.758 MW	Diesel/Bunker	Unknown	Unknown
COS Thermal Unit 2	2013	2.5 MW	Diesel/Bunker	Unknown	Unknown
COS Thermal Unit 3	2014	2.5 MW	Diesel/Bunker	Unknown	Unknown
COS Thermal Unit 5	1961	2.81 MW	Diesel/Bunker	Unknown	Unknown
COS Thermal Unit 6	2010	1.25 MW	Diesel/Bunker	Unknown	Unknown
COS Thermal Unit 7	1950	1.42 MW	Diesel/Bunker	Unknown	Unknown
COS Thermal Unit 8	1983	5.306 MW	Diesel/Bunker	Unknown	Unknown

b. See response to IR-5 a).

c. MECL completed a major overhaul of its generating units at the Charlottetown Thermal Generating Station (CTGS) during the Life Extension Program completed during the time period of 1990 to 1995. The costs of the refurbishment work undertaken during the Program were approximately $27 Million in 1995 Canadian Dollars.

A list of reports on major refurbishments completed on each of the units since 1990 is included as IR-5 - Attachment 1. A high-level summary is included below in Table 3. MECL does not have records that reflect major refurbishments that occurred prior to 1990.

Table 3 Installation and Recent Significant Maintenance Dates on Major Units at CTGS		
Unit	**Activity**	**Date**
Turbine – Generator 7	Installation Life Extension Program Turbine Blade Inspection	1956 1994 2001
Turbine – Generator 8	Installation Life Extension Program Turbine Blade Inspection Overhaul Rewedge Generator Stator	1960 1991 2001 2006 2006
Turbine – Generator 9	Installation Life Extension Program Turbine Blade Inspection Overhaul Rewedge Generator Stator	1963 1990, 1993 2001 2002 2005
Turbine – Generator 10	Installation Life Extension Program Turbine Blade Inspection Overhaul Rewedge Generator Stator	1968 1991 2001 2004 2005
Boiler 2	Installation New Burner	1997 2005
Boiler 4	Installation Significant Refurbishment	1954 1992
Boiler 5	Installation Significant Refurbishment New Burners	1960 1991 2007-2008
Boiler 6	Installation	1976
Boiler 9	Installation Significant Refurbishment Boiler Rebuilt	1963 1990 1995
Boiler 10	Installation Significant Refurbishment Install T-Jet Burners	1968 1991 2007

d. See response to IR-5 a).

e. See response to IR-5 a).

f. See response to IR-5 a).

g. See response to IR-5 a).

h. The firm capacity of each unit is as follows (as of January 1, 2019):

Generating Unit	Firm Capacity (MW)
CTGS #8	10
CTGS # 9	19
CTGS #10	19
Borden CT1	15
Borden CT2	25
Charlottetown CT3	49
Summerside Generation (combined - assumed)	15
Wind Generation (combined)	21[1]
Total	**158**

i. MECL's thermal units are "standby" generator units and as such the average annual capacity factors are in the 0.0% to 1.6% range. Refer to Table 4 and Table 5 below for the calculation of average annual capacity factors for MECL-owned units over the period 2014 - 2018. As noted in IR-5 a) MECL does not have the details required to answer this question for all generating units owned by other entities.

Table 4 Average Annual Capacity Factors for CTGS Thermal Units					
	2014	**2015**	**2016**	**2017**	**2018**
Gross Generation (MWh)					
Steam Turbine 7	50	3	-	62	-
Steam Turbine 8	10	24	119	40	-
Steam Turbine 9	2,734	2,333	801	1,176	-
Steam Turbine 10	1,862	1,646	625	664	-
Capacity Factor (%)					
Steam Turbine 7	0.08%	0.00%	0.00%	0.09%	0.00%
Steam Turbine 8	0.01%	0.03%	0.14%	0.05%	0.00%
Steam Turbine 9	1.56%	1.33%	0.46%	0.67%	0.00%
Steam Turbine 10	1.06%	0.94%	0.36%	0.38%	0.00%

[1] ELCC value of wind. For further information refer to response to IR-13.

Table 5 Average Annual Capacity Factors for Combustion Turbines					
	2014	**2015**	**2016**	**2017**	**2018**
Gross Generation (MWh)					
Combustion Turbine 1	227	89	52	72	96
Combustion Turbine 2	150	205	236	291	317
Combustion Turbine 3	3,269	4,327	2,707	3,034	2,330
Capacity Factor (%)					
Combustion Turbine 1	0.17%	0.07%	0.04%	0.05%	0.07%
Combustion Turbine 2	0.07%	0.09%	0.11%	0.13%	0.14%
Combustion Turbine 3	0.76%	1.01%	0.63%	0.71%	0.54%

IR-6 Please describe each of MECL's purchased power agreements:

a) Who is the supplier?

b) On what basis are the quantities of energy to be delivered determined?

c) What are the energy prices associated with this agreement and on what basis are the prices of energy to be delivered determined?

d) If the agreement includes the purchase of capacity, what is the specified capacity, and what percentage of it is firm capacity?

e) What are the capacity prices associated with this agreement and on what basis are they determined?

f) What economic, operational or other constraints are there on the delivery of either the capacity or energy?

g) What is the term of the agreement?

h) Please identify any third party to the agreement and the role of the third party?

<u>Response</u>

a. MECL has power purchase agreements with:

- The PEI Energy Corporation, who provides wind energy generation to MECL from six wind energy generation facilities, and
- New Brunswick Energy Marketing (NBEM), who provides the balance of MECL's energy that is not otherwise supplied by MECL's participation in Point Lepreau or Summerside's on-Island backup thermal or diesel generation.

b. The quantities of energy to be delivered are determined as follows:

- Wind energy generation – MECL agrees to take all output from the six wind facilities under contract. The estimated annual delivery amounts were based on projected capacity factor of each facility; and
- NBEM power purchase agreement – NBEM supplies all of MECL's energy requirements that are not otherwise supplied by a) wind generation under contract to MECL, b) on-Island thermal and diesel generation that is primarily dispatched only in backup or contingency situations, and c) MECL's participation in Point Lepreau.

c. & d.

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e. See response to IR-6 d) for the capacity prices.

The prices were agreed upon with NBEM during the new Energy Purchase Agreement negotiations.

MECL reviewed the most recent ISO-NE forward capacity auctions results which provide a benchmark for capacity pricing in the Maritimes. In addition, MECL reviewed the capacity demands of the New Brunswick and Nova Scotia jurisdictions to gauge the availability of surplus capacity in the Maritimes area.

MECL provided the following response to IR-9 in the Responses to Interrogatories – Commission Expert (UE20944), August 2018:

"MECL was reasonably confident that NBEM would have sufficient generating capacity and energy supply over the proposed timeframe of the Agreement, based on information included in the NB Power 2017 IRP. MECL focused in particular on the IRP's projections for generating capacity (Figure 8) and its load forecast (Figure 11). Capacity was expected to remain relatively constant until at least 2024, and the load was projected to increase at 0.7% per year.

Nova Scotia energy and demand forecasts were gained through the 'Nova Scotia Power 10 Year System Outlook 2017 Report' issued by the Nova Scotia Utility and Review Board, dated June 30, 2017.

MECL did not review New England energy demand forecasts in detail."

f. The 300 MW firm transfer capacity limit on the NB-NS/PEI interface limits the amount of energy and capacity that can be sourced from off-Island resources.

In real-time, the availability of transmission and generation in New Brunswick can impact the amount of energy that can be delivered to the Island over the NB-PEI interconnection. In addition, inaccurate scheduling can have a short-term impact on energy deliveries.

g. See response to IR-6 c).

h. MECL has two power purchase agreements with third parties involved. This third party involvement is highlighted below:

- The *10 MW Renewable Energy Purchase Agreement between PEI Energy Corp and Maritime Electric Company, Limited and The Government of Prince Edward Island and Wind Energy Institute of Canada*
  - The Government of PEI owns the renewable energy credits produced by the wind facility as dictated by provincial legislation; and
  - The Wind Energy Institute of Canada owns and operates the wind generation facility and sells all of its energy output to the PEI Energy Corporation, who in turn sells the energy to MECL.

- The *39 Megawatt Wind Power Purchase Agreement between Prince Edward Island Energy Corporation and Maritime Electric Company, Limited and the Government of Prince Edward Island*
  - The Government of PEI owns the renewable energy credits produced by the wind facility, as is dictated by provincial legislation.

Engie Norway is not an official third party to the latter power purchase agreement, however Engie Norway, as owner and operator of the Norway 9 MW wind generation facility, sells all its energy output to the PEI Energy Corporation, who in turn sells the energy to MECL.

The Aeolus Power Purchase Agreement referenced in IR-6 c) had third party involvement when it was first in effect. The PEI Energy Corporation subsequently purchased the Aeolus facilities, resulting in only two parties to the agreement.

IR-7 With respect to Lepreau participation agreement:

a) Does the portion of Lepreau devoted to PEI belong to MECL? If not, who owns it, and under what terms and conditions is it provided to MECL?

b) What is the delivery point for the power and energy delivered under the agreement?

c) If the delivery point is at the Lepreau generating station, at what interconnection point is it delivered to the PEI transmission system, and under what conditions and tariffs is it delivered to the PEI transmission system?

d) What capacity and annual energy is provided at the delivery point?

e) If the delivery point is not at the interconnection of the NB Power and PEI transmission systems, what demand and energy losses are incurred to get it to that point?

Response

a. The Point Lepreau Participation Agreement is between New Brunswick Power Corporation (NBPC) and MECL, and provides MECL with an Entitlement (not ownership) to 30 MW of capacity and associated energy from the Point Lepreau generating unit under terms and conditions that are intended to ensure that NB Power recovers in all events all costs associated with the provision and generation of the power and energy to which MECL is entitled. In effect, MECL pays owner's costs and assumes owner's risks.

b. The Delivery Point for the power and energy delivered under the agreement associated with MECL's Entitlement is the Murray Corner, NB Switching Station as set out in the Interconnection Agreement between NB Power and MECL and referenced in the Point Lepreau Participation Agreement.

The Purchase Point is at the low voltage terminals of the step-up transformer for the Lepreau generating unit.

c. See response to IR-7 b) and e).

d. The Capacity at the Delivery Point is 29 Megawatts (MW).

The annual energy provided at the Delivery Point would be approximately 254,040 Megawatt-hours (MWh), which assumes no annual maintenance outage to the generating plant.

e. The Purchase Point is the measurement point for power and energy associated with MECL's entitlement, and is at the low voltage terminals of the step-up transformer of the generating unit at the Point Lepreau site.

The Delivery Point for the power and energy delivered under the agreement associated with MECL's Entitlement is at the Murray Corner, NB switching station as set out in the Interconnection Agreement between NB Power and MECL.

The losses associated with the energy flow from the Purchase Point to the Delivery Point are as follows:

- MECL Entitlement – 660 MW x 4.545 % = 30 MW (at Point Lepreau station);
- NB system losses – 3.33 % (as per current NB OATT); and
- Capacity and Power at Delivery Point – 30 MW x (1 – 0.0333) = 29.0 MW.

IR-8 Regarding the PEI underwater cable interconnection with NB Power:

a) When was this interconnection first made?

b) Why was the interconnection made?

c) How many cables ran between PEI and NB when the interconnection was first made?

d) At what voltage did the cables operate?

e) What was the capacity of the first interconnection?

f) What was the cost of the first interconnection?

g) What parties provided funding for the first interconnection, and how much was contributed by each party?

h) Please provide a copy of any studies which supported the interconnection as the best option for PEI.

i) What is the current status of the initial interconnection? Has it been retired?

j) What was the cost of the second interconnection in 2017, what parties provided funding for the project, and how much was contributed by each party?

k) How many cables are currently in service between PEI and NB?

l) At what voltage do the cables operate?

m) What is the current capacity of the interconnection?

n) Who owns the interconnection? If it is not owned by MECL, please provide terms and conditions under which MECL uses it, including the annual cost to MECL and the basis on which those costs are determined.

o) If MECL does not own the interconnection, please provide a copy of the contract between MECL and the interconnection owner, under which MECL uses the interconnection.

p) How are interconnection costs included in OATT? If they are not included, please explain why not.

Response

a. The first interconnection was made with NB Power in 1977. The original interconnection consisted of a cable riser and switching station at Murray Corner NB, two 138 kV submarine cables between Murray Corner and Richmond Cove, PEI, a cable riser station at Richmond Cove, and two 138 kV lines between Richmond Cove and the Bedeque Substation.

b. Prior to the interconnection, PEI's generation came from a combination of thermal generation (supplied by heavy fuel oil), combustion turbines (supplied by diesel) and diesel generators. Without the cables, the Island would have continued to be highly reliant on oil for electricity generation, and the consumer price for electricity would have been considerably more expensive than the mainland alternative.

The interconnection was made to give the Island access to generation sources located on the mainland, which had better economies of scale and offered the possibility of alternate fuel sources such as coal and hydro.

c. Two 3 phase, 100 MW, 138 kV submarine cables were installed in 1977 between Murray Corner and Richmond Cove.

d. 138,000 Volts (i.e. 138 kV)

e. The capacity of the first interconnection was 200 MW.

f. The cost of the first interconnection was $36 million in 1977.

g. The total cost of $36 million for the first interconnection was funded as follows:

- $18 million grant from the Federal Government;
- $9 million funded directly by the Province of PEI; and
- $9 million loan taken out by the Province of PEI to be repaid with revenues collected from PEI electricity users by MECL through rates.

Included in the above cost was a contribution-in-aid-of-construction that the Province of PEI made to NB Power to build one overhead 138 kV line (denoted L1142) from the Memramcook, NB Substation to the Murray Corner Switching Station.

h. Montreal Engineering Company, Limited completed a Maritime Electric Company P.E.I. – Mainland Cable Interconnection Transient Stability Study dated January, 1977 which states in the Introduction:

1. Previous Works
"In the late summer of 1972 the economic feasibility of a submarine cable connection between Prince Edward Island and the mainland had been established."

i. The interconnection cables installed in 1977 are still in service.

A portion of NB line L1142 was removed to accommodate the updated line connections when the second interconnection was completed in 2017; the remainder of line L1142 is operational.

j. The total cost of the second interconnection was $137 million and was funded as follows:

- $65 million grant from the Federal Government; and
- $72 million loan taken out by the Energy Corporation, which will be repaid by MECL and Summerside with revenues collected from PEI electricity users through rates.

k. There are currently four cables in service between PEI and New Brunswick. There are two 100 MW cables from the first interconnection in 1977 and two 180 MW cables from the second interconnection in 2017.

There are three 138 kV transmission lines from the Memramcook Substation that supply PEI – one for each of the two new 180 MW submarine cables and one for the two 100 MW submarine cables installed in 1977. Because the impedance of the overhead transmission lines is large relative to the impedance of the submarine cables, the PEI load is shared approximately equally between the three overhead lines which results in the cables being loaded approximately in proportion to their ratings.

l. The four interconnecting cables are operated at 138 kV.

m. The capacity of the first interconnection is 200 MW and the capacity of the second interconnection is 360 MW. The total combined capacity of the interconnection is 560 MW.

n. The first interconnection (1977) is owned by the Province of PEI. The second interconnection (2017) is owned by the PEI Energy Corporation.

MECL operates the combined interconnection on behalf of the Province of PEI and the Energy Corporation according to the terms of an agreement entitled *PEI-NB Interconnection Lease Agreement Between the Province of Prince Edward Island and The Prince Edward Island Energy Corporation and Maritime Electric Company, Limited, July 2017* which has been filed with Commission.

This agreement states, in part, the following:

Under Article 2 – Agreement to Lease
"2.1. Following the in-Service Date, the Owners will retain ownership of the Interconnection Facilities but lease and deliver administration and operational control of the Interconnection Facilities to MECL. MECL shall operate, repair and maintain the Interconnection Facilities in accordance with Good Utility Practice on behalf of the Owners at MECL's expense throughout the Service Life."

Under Article 7 – Summerside and MECL Rights to Interconnection Capacity
"7.3. The Parties agree that MECL and Summerside will share the import capacity from NB to PEI of the Interconnection Facilities based on each of MECL's and Summerside's ratio of contributions towards the Debt."

Under Article 12 - Billing and Payment

"12.3 Subject to approval of the Commission, MECL shall include the costs that it incurs for the operation, maintenance, repair, clean up, reporting and restoration of the Interconnection Facilities as per Sections 12.1 and 12.2 in its annual revenue requirement and MECL shall collect the costs from Transmission Users in accordance with the provisions of the OATT."

The 'Debt' referred to in Article 7.3 above is the outstanding debt owed by the Province of PEI for the construction of the new interconnection. It is defined in the *PEI-NB Interconnection Facilities Debt Collection Agreement Between the Province of Prince Edward Island and The Prince Edward Island Energy Corporation and Maritime Electric Company, Limited and City of Summerside, July 2017*, which also is filed with the Commission. Article 2 of this Agreement states the following:

"Article 2 – Debt

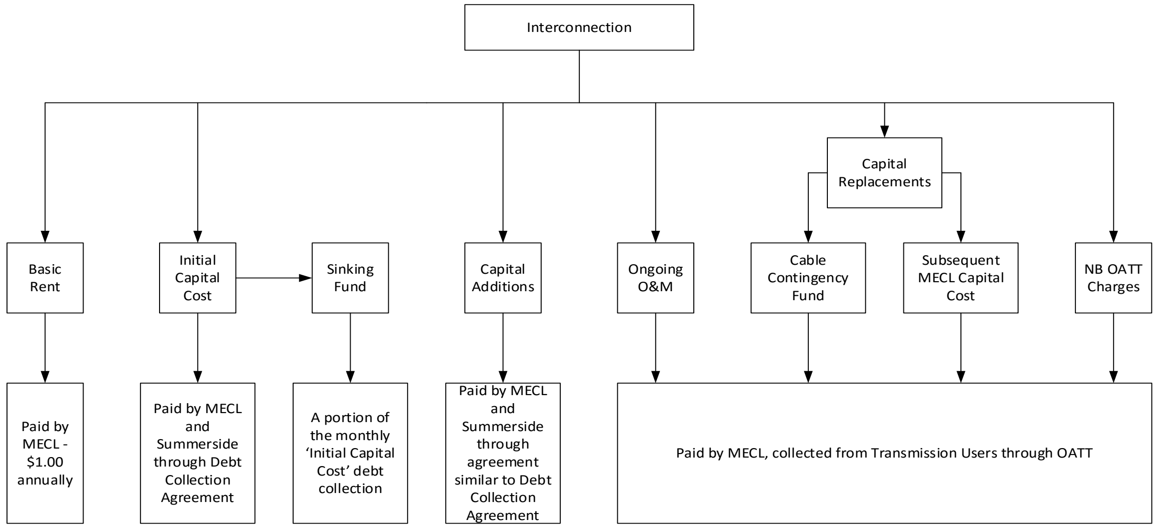
2.1 The Debt incurred by the Energy Corporation in respect of the Initial Capital Cost of Interconnection #2 and associated parts of the NB Interconnection Transmission is as set out in Schedule "A".

2.2 Pursuant to the terms of this Agreement, the Debt, including all interest charges, is to be collected by MECL and Summerside from their respective customers as part of the lawful rates, tolls and charges, on behalf of the Energy Corporation and remitted to the Energy Corporation as required by the terms of this Agreement."

The current annual cost to MECL of this Debt is $3,127,489.68. This figure will be recalibrated after the first five year period of the Debt Collection Agreement, as dictated by the terms of that agreement.

o. The Interconnection Lease Agreement and Debt Collection Agreement are attached as IR-8 - Attachment 1 and IR-8 – Attachment 2 to this document.

p. The interconnection costs are recovered both through and outside the OATT. The diagram below shows a breakdown of the cost recovery associated with the cable interconnection.



Interconnection costs included in the OATT are recovered from Transmission Users via Schedule 7 (Firm Transmission Service), Schedule 8 (Non-Firm Transmission Service) and Attachment H (Network Transmission Service).

IR-9 Please explain the basis on which the most recent upgrade of the interconnection with NB determined to be the most attractive supply option, and provide any supporting planning studies.

Response

The justification for the new interconnection was not supported by a planning study. It was primarily based on the age of the original submarine cables, and growth in the P.E.I. electricity load.

The original interconnection was installed in 1977 with an expected submarine cable life of 40 years. The Island peak load at the time was less than 100 MW.

MECL had been investigating adding facilities in order to provide security of supply for MECL customers since the early 2000's. MECL added a 50 MW combustion turbine ('CT3') in Charlottetown in 2005 to provide backup for its customers; at that time CT3 was more economical than a new interconnection plus purchasing 50 MW of generating capacity.

MECL continued to look at ways for providing security of supply, and a number of factors came together to provide the final justification for the new interconnection in 2014-15:

- An oil leak in Cable #1 in 2012 removed that cable from service for three months in order for repairs to be completed. All on-Island backup generation was required to operate in order to ensure supply continuity. This leak was repaired during the summer months, which is not the Island peak loading period.
- Loss of one of the existing submarine cables limited imports over the remaining cable to 100 MW. During the 2012 cable outage there was approximately 160 MW of on-Island dispatchable diesel and thermal generation, and 173 MW of non-dispatchable wind generation. This meant, in the absence of wind, a maximum on-Island load of 260 MW could be supplied.
- The Island peak load grew from 208 MW in 2005 to 254 MW in 2014.
- By 2014 the Charlottetown Thermal Generating Station ('CTGS') had facilities that were approaching 60 years of age. A 15 year life extension was completed on the facility in 1990-95, and a further life extension study in 2009 showed that additional capital infusion to extend the life even longer was not economical compared to the cost of new on-Island capacity.
- A cable outage during late fall or early winter that would require submarine repairs could result in a six month cable outage, as repairs likely couldn't be undertaken until the following April or May when Northumberland Strait ice conditions improve.

MECL applied to the Commission in 2015 to add another combustion turbine on the Island in order to provide security of supply and generation capacity. Schedule 3 of that application is shown below:

	Actual	Forecast									
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
MECL peak load (MW)	227	240	245	251	259	267	275	282	291	299	307
Less reduction due to DSM			2	4	6	8	10	10	10	10	10
Forecast peak load	227	240	243	247	253	259	265	272	281	289	297
Generating capacity (MW):											
- Charlottetown Plant	60	55	55	55	55	38	19				
- Borden Plant	40	40	40	40	40	40	40	40	40	40	40
- Combustion Turbine 3	49	49	49	49	49	49	49	49	49	49	49
- Wind Effective Load Carrying Capability	21	21	21	21	21	21	21	21	21	21	21
- Maximum off-Island (includes Pt Lepreau)	80	80	80	80	80	80	80	80	80	80	80
- Short term capacity agreement	27	27	27								
- Combustion Turbine 4				50	50	50	50	50	50	50	50
- Additional capacity							50	50	50	50	50
subtotal	277	272	272	295	295	278	309	290	290	290	290
Capacity surplus (shortfall)	50	32	29	48	42	19	44	18	9	1	(7)

MECL withdrew the application after NB Power upgraded their transmission system to allow more firm transfer capacity across the NB-NS/PEI interface. This increased the amount of firm transmission available to the Island from 80 MW to 100 MW, based on the loss one submarine cable, and thus MECL was limited to a maximum amount of 100 MW of off-Island generating capacity. The declining status of the CTGS, combined with a limitation of off-Island generating capacity, left the Island with the prospect of a generating capacity shortfall.

With little apparent public appetite for additional on-Island oil-fired generating capacity, PEI was facing a security of supply issue. This became a public policy issue, and the Province of PEI expressed its support of adding new interconnection capacity in 2015.

IR-10 Please describe MECL's transmission system:

a) Does it include the interconnection with NB? If not, please explain why not.

b) At what voltages does the MECL transmission system operate?

c) What is the minimum voltage considered to be transmission, rather than distribution?

d) For cost allocation purposes, are transformers whose high side voltage is transmission voltage but whose low side voltage is distribution voltage, considered to be transmission or distribution assets?

Response

a. MECL does not own the interconnection but it is considered to be part of MECL's transmission system for operating and maintenance purposes.

The interconnection is owned by the Province of PEI. Under the terms of the MECL Interconnection Agreement operates and maintains the interconnection as part of the Company's transmission system.

b. MECL's transmission system operates at 138 kV (138,000 Volts) and 69 kV (69,000 Volts).

c. 69 kV (i.e. 69,000 Volts) is the lowest transmission voltage.

d. In the Chymko Cost Allocation Study, transformers whose high side voltage is transmission voltage but whose low side voltage is distribution voltage are functionalized as "Substations". Since they are not included with the "Transmission" function, they are deemed to be distribution assets.

IR-11 What are the capacity and energy losses (in percent) at the transmission and distribution levels, and how are they determined?

Response

The energy losses for 2017 were:

- 2.2% for transmission; and
- 5.2% for distribution.

Transmission system losses are determined as the difference between metered inputs to the transmission system and metered outputs from the transmission system.

All inputs to the transmission system from the interconnection with New Brunswick, from wind farms and from MECL's own generators are metered. All of MECL's distribution substations are metered, usually on the low voltage side of the transformers. Since distribution substations are considered to be part of the distribution system for purposes of the Open Access Transmission Tariff (OATT), losses in distribution substation transformers are estimated and treated as part of the input to the distribution system, and thus become part of distribution system losses rather than transmission system losses.

Distribution system losses are determined as follows:

- metered inputs to the distribution system;
- plus estimated losses in distribution substation transformers;
- plus energy received from customer-owned generation (mostly net metering);
- minus energy used at Company facilities; and
- minus distribution system energy sales.

Capacity losses are system losses at the time of peak load. For 2017 these are estimated as:

- 2.5% for transmission; and
- 5.9% for distribution.

Capacity losses for each of the transmission and distribution systems are estimated as follows:

- The annual energy losses are broken down between iron losses and copper losses;
- Iron losses are the losses in the steel cores of transformers. These losses are essentially independent of load. The estimated annual amount of these losses (in MWh) is divided by the 8,760 hours in a year to get a MW losses value that is deemed to be constant year round;
- Copper losses are the losses in transmission line conductors and in the windings of transformers. These losses vary as the square of the load. A MW losses value is calculated for the load at system peak; and
- The year round iron losses MW value and the copper losses MW value for system peak are added to get the estimated losses at system peak.

IR-12 For each rate class served by MECL:

a) What is the total coincident and non-coincident demand, and on what basis are these determined?

b) What is the total non-firm coincident demand, and on what basis is it determined?

c) What are the total annual sales, and on what basis are they determined?

Response

a. The values in the table below have been taken from Schedule 2.2 of the 2017 Chymko Cost Allocation Study. These demands are determined for Cost Allocation Study purposes.

At Distribution Primary for 2017 (kW)		
	1CP (Coincident Peak Demand)	**NCP (Non-Coincident Peak Demand)**
Residential	155,108	195,749
General Service	54,696	88,719
Small Industrial	14,235	29,032
Large Industrial		
Street Lighting	1,389	1,444
Unmetered	355	355

The above values include distribution system losses.

<u>Coincident Peak Demands</u>
For Residential, General Service and Small Industrial the coincident peak demand values are estimates. The metering used for these customers does not provide time of use information, and the class loads at time of system peak are estimated by applying annual or monthly load factors to the corresponding metered energy amounts. The load factors come from load studies conducted by other utilities and a load study done by MECL in the early 1990s.

All Large Industrial customers have time of use metering, so the load for each customer at time of system peak can be determined. However, to show a total amount could be confusing because not all Large Industrial customers are served at distribution voltage.

For Street Lighting and Unmetered the coincident peak load can be calculated based on knowing the connected loads and assuming that they are all on at time of system peak.

<u>Non-Coincident Peak Demands</u>
For Residential the non-coincident peak demand value is also an estimate. The meters

used for Residential customers are energy only meters; they do not provide the maximum customer load during the month. Similar to coincident peak demand, the non-coincident peak demand for the Residential class is estimated based on load factors developed from load studies.

For General Service and Small Industrial the meters used generally provide the maximum load for each customer during the month. The non-coincident peak load for a class can be estimated by summing the demand readings for a month for all the customers in the class and applying a diversity factor to arrive at a combined maximum load for the class that month. The highest of the monthly non-coincident peaks calculated this way is the non-coincident peak load for that class for the year.

Since all Large Industrial customers have time of use metering, the non-coincident load can be determined by finding the hour when the combined load of the customers is greatest.

For Street Lighting and Unmetered the load is essentially constant when on, so the coincident and non-coincident peak loads are the same, except for area lighting that is connected during the summer on a seasonal basis related to tourism and cottages.

b. Using data from Schedule 2.2 of the 2017 Chymko 2017 Cost Allocation Study, the total non-firm coincident peak demand for 2017 is derived below, as at the input to the transmission system (i.e. the kW values include transmission and distribution losses).

Non-Firm Coincident Peak Load for 2017 (kW)		
	General Service	**Large Industrial**
1CP – Transmission input	58,081	16,203
Less 1CP – Transmission input firm	57,419	2,513
1CP – Transmission input non-firm	662	13,690

Each interruptible customer has the option of declaring a portion of their load that is to be considered firm, and then all load in excess of that amount is deemed to be interruptible.

Each interruptible customer has time of use metering, and the amount of interruptible load for each customer is determined by subtracting the firm load portion from their total metered load at time of system peak.

c. MECL's annual sales by Rate class were as follows for 2017:

Residential	577,014 MWh
General Service	384,918
Small Industrial	104,569
Large Industrial	133,622
Street Lighting	5,519
Unmetered	2,416
Total	1,208,058 MWh

The amounts shown above for Small Industrial and Large Industrial are different than the sales amounts for those classes as shown in Schedule 2.2 of the 2017 Chymko Cost Allocation Study. The reason is that during 2017 several customers moved from Small Industrial to Large Industrial. For purposes of the Cost Allocation Study, it was decided to treat those customers as if they had been in the Large Industrial class for the entire year.

For all rate classes except Street Lighting and Unmetered, the sales amounts are based on monthly meter readings.

For Street Lighting, the monthly usage for each type of light is multiplied by the number of each type of light in service to calculate a monthly sales amount.

For Unmetered, the connected load for each customer is known, along with whether the load is on for 12 hours per day or 24 hours per day. The monthly sales amount is calculated based on this information.

IR-13 Regarding wind generation, what portion of nameplate capacity is considered to be firm supply for system planning purposes, and on what basis is that portion determined?

Response

Based on the electric utility industry probabilistic Loss of Load Expectation (LOLE) methodology, MECL has assigned an Effective Load Carrying Capability (ELCC), or effective capacity value, of 21 MW to the 92 MW of wind generation that the Company purchases from the PEI Energy Corporation. The ELCC of 21 MW is the additional load which the system can supply with 92 MW of wind generation added to the system, while still maintaining the same level of reliability of supply.

IR-14 What percentage of MECL's residential customers has electric heat, and what percentage has electric hot water?

Response

MECL estimates that 30% of Residential customers have electric space heating and 50% have electric hot water heating.

<u>IR's 15- 24 relate to the Chymko CAS</u>

IR-15 With respect to Schedule 6.0 of the Chymko CAS:

a) Please describe what is included in Account 7000 (NB Power Assured) and explain why no portion of it is considered Demand related.

b) Please describe what is included in Account 7008 (Other Energy).

c) Please describe what is included in Account 7046 (NB Power Secure) and explain how it is different from Account 7000 and why no portion of it is considered Demand related.

d) Please describe what is included in Account 7049 (Capacity Other).

e) Please describe what is included in Account 7050 (NB Power Firm) and explain why no portion of it is considered Demand related.

f) Please describe what is included in Accounts 7053 (Imbalance Energy) and 7054 (Imbalance Premium). If either or both is related to OATT, please explain why it is not included in Account 7510.

g) Please describe what is included in Account 7055 (COS Energy Purchase) and explain why it is all assigned to Demand.

h) Please describe what is included in Account 7056 (E-Tagging and Scheduling) and explain why none of it is Demand related.

i) Please describe what is included in Account 7058 (IPL Transmission Sch 1,2, 7) and explain why it is all assigned to Demand. Also, please explain why it is not included in Account 7510 (OATT).

j) Please describe what is included in Account 7150 (ECC Operations) and explain why none of it is assigned to Demand.

k) How are the costs included in Account 7150 different from the ECC costs that are included in OATT? If they are not different, are they not captured in Account 7510?

l) Please describe what is included in Account 7415 (MICF Gov Misc Lab & Exp) and explain why none of it is assigned to Demand.

m) Please describe what is included in Account 7510 (OATT) and explain why none of it is assigned to Demand.

n) Please describe what is included in each of Accounts 7500 – 7508 and Accounts 6340 – 6348.

o) Please break down account 9400 (Amortization) to show amortization associated with generation, transmission, distribution separately. Please also provide the generation portion broken down by generating station, with the Charlottetown CT shown separately from the Charlottetown steam units.

p) Please describe what the cost in Account 9420 (Amortization – DSM Costs) covers and provide its derivation. In answering this question, please show how this cost relates to the discussion in Section 4.2.1 of the November 28, 2018 filing.

q) What are the annual costs to MECL for its use of the interconnection with NB, and where are those costs included in Schedule 6.0?

Response

a. Account 7000 accounts for purchases of Assured Energy from NBEM through the Energy Purchase Agreement.

No portion of the Assured Energy is classified to the 'Demand' portion of Power Supply, since Assured Energy is solely energy-based. MECL provides the associated backup capacity from the CTGS and the Borden Generating Station.

b. Account 7008 provides for the purchase of renewable energy (excluding large scale wind) from on-Island sources. It includes energy from net metering, the Wind Energy Institute of Canada wind test site (small-scale wind) and the City of Charlottetown Pollution Control Centre.

c. Account 7046 accounts for purchases of Secure Energy from NBEM through the Energy Purchase Agreement.

Secure Energy is backstopped by MECL's CT3 combustion turbine. Assured Energy is backstopped by MECL's Borden CT1 and CT2 and CTGS, as is further explained in the response to IR-32.

No portion of the Secure Energy is classified to the 'Demand' portion of Power Supply, since Secure Energy is solely energy-based.

d. Account 7049 contains costs for capacity purchased from NBEM outside of the Energy Purchase Agreement.

This is primarily for short-term capacity to get through periods where MECL is capacity deficient. This can occur for a number of reasons, including unexpected high load or a MECL unit being out of service.

e. Account 7050 accounts for purchases of Firm Energy from NBEM through the Energy Purchase Agreement; however, it does not provide for the corresponding capacity.

No portion of the Firm Energy is classified to the 'Demand' portion of Power Supply, since Firm Energy is solely energy-based. The cost of capacity associated with Firm Energy is accounted for in Account 7002.

f. Account 7053 provides for the purchase and sale of energy outside the imbalance bandwidths from the NB System Operator when schedule loads do not match actual loads.

Account 7054 provides for the penalty portion of the imbalance bill from the NB System Operator when scheduled loads do not match actual loads. No energy is included.

Neither of these accounts is related to the OATT.

g. Account 7055 provides for the purchase of energy from the Summerside during periods of system constraint.

MECL and Summerside cooperate on supply of energy when system conditions require on-Island generation to be operated. As such, Summerside's generation is similar to MECL's generation in terms of operation, and its costs are allocated similar to MECL's.

As MECL purchases little energy from Summerside, the Summerside generator is treated similar to MECL's physical generation plant.

MECL's on-Island generation plant – the combustion turbines located at Borden and Charlottetown, and the CTGS – are all fully classified to the 'Demand' portion of Power Supply. Therefore MECL's expense associated with Summerside's generation is also classified as 100 % Demand.

Note that the fuel associated with MECL's combustion turbines is fully classified to the 'Energy' portion of Power Supply. The fuel for the CTGS is classified to "Demand" because most of it is used for testing and plant heating.

h. Account 7056 provides for the fees required to utilize the e-tagging system for entering energy requirements.

No portion of these fees is classified to the 'Demand' portion of Power Supply, since these fees pertain to scheduling of energy deliveries, and do not relate to capacity or any other demand function.

i. Account 7058 deals with transmission capacity on the International Power Line ('IPL'). MECL has a long-term firm reservation of 30 MW in New Brunswick on the IPL for delivery of energy from New England to Murray Corner. MECL reassigns this transmission capacity to NBEM in order that NBEM can schedule firm energy and generating capacity with it to MECL.

According to the Chymko CAS, Section 3.1, under paragraph 37:

"Transmission lines are part of a bulk delivery system that ultimately services all utility customers, including wholesale customers. Transmission infrastructure is generally unaffected by the additional of one more customer, unless the addition of that customer is expected to materially affect peak system demand. Chymko Consulting therefore considers transmission lines to be demand related and allocates these functions on the basis of coincident peak demand."

It is not included in Account 7510 (OATT) because the IPL is located off-Island, and therefore is not part of the PEI transmission system. The only on-Island customer it benefits is MECL and only MECL customers are responsible for its costs.

j. Account 7150 includes costs pertaining to the operation of the Energy Control Centre (ECC).

Of the portion of the expenses (25%) in Account 7150 that are functionalized to Power Supply (which is comprised of Generation and Purchased Power), none are allocated to Demand, since the main purpose of the ECC is to manage and coordinate the delivery of energy supply.

Paragraph 36 in the *Chymko 2017 Cost Allocation Study*, June 26, 2017 stated:

> "*Consistent with previous studies, MECL's Energy Control Centre (ECC) is classified as <u>ninety five percent energy related</u> because the main purpose of the ECC is to manage and coordinate the delivery of energy supply. Because at least a portion of ECC activities must ultimately feed into long term resource planning, <u>five percent</u> of the ECC expenses are classified as <u>demand related</u>." {underlining added}*

This wording does not properly reflect the Chymko study, since the CAS was undertaken with the ECC Power Supply costs being 100% allocated to energy, not Demand. Paragraph 36 should be replaced with the following:

> *"MECL's Energy Control Centre (ECC), the portion of which that is functionalized to power supply, is classified as one hundred percent energy related. In the context of power supply, the main purpose of the ECC is to manage and coordinate the delivery of energy. Though a portion of ECC activities must ultimately feed into long term resource planning, this is acknowledged by functionalizing three quarters of the ECC to transmission and distribution, where classification to demand is discussed as follows."*

The remainder of Account 7150 is functionalized to Transmission (25%) and Distribution related (50%). These amounts are classified as "energy" related because they are associated with operating and maintenance activities.

k. Most of the costs associated with the ECC are captured in Account 7150. A portion of ECC costs – costs associated with the ECC's direct involvement with operations in connection with OATT – are captured as part of Account 7510 (OATT Administration).

l. Account 7415 captures all operating and maintenance expenses associated with the submarine cables portion of the NB-PEI interconnection, including the debt repayment responsibilities of MECL that have been dictated in the *PEI-NB Interconnection Facilities Debt Collection Agreement Between the Province of Prince Edward Island and The Prince Edward Island Energy Corporation and Maritime Electric Company, Limited and City of Summerside, July 2017*.

The interconnection was completed to give Island electric customers access to more energy supply sources located off-Island, and thus the facilities are fully classified to the 'Energy' portion of Power Supply.

m. Account 7510 provides for the expenses to administer the OATT, and includes a portion of ECC expenses as mentioned in the response to IR-15 j).

The OATT administration function mainly deals with accounting for energy-related and ancillary service products, which are energy related.

Therefore no portion of these costs is classified to the 'Demand' portion of Power Supply, since the function deals primarily with these fees pertain to scheduling of energy deliveries, and does not relate to capacity or any other demand function.

n. At a high level, Accounts 7500 – 7508 are MECL's expenses resulting from taking transmission services under the OATT:

- 7500 – Expenses for Network Integration Service under Attachment H of the OATT
- 7502 – Expenses for Scheduling, System Control and Dispatch Service under Schedule 1 of the OATT
- 7503 – Expenses for Regulation and Frequency Response Service under Schedule 3 of the OATT
- 7504 – Expenses for Reactive Supply and Voltage Control from Generation Sources Service under Schedule 2 of the OATT
- 7505 – Expenses for Energy Imbalance Service under Schedule 4 of the OATT
- 7507 – Expenses for Residual Uplift under Schedule 10 of the OATT
- 7508 – Expenses for Non-Capital Support Charge Rate under Schedule 9 of the OATT

At a high level, Accounts 6340 – 6348 are MECL's revenues from providing transmission services under the OATT, and include revenues from MECL's use of the system as well as the other Transmission Users

- 6340 – Revenues for Firm and Non-Firm Point to Point Service under Schedules 7 and 8 of the OATT, and for Network Integration Service under Attachment H of the OATT
- 6342 – Revenues for Scheduling, System Control and Dispatch Service under Schedule 1 of the OATT
- 6343 – Revenues for Regulation and Frequency Response Service under Schedule 3 of the OATT
- 6344 – Revenues for Reactive Supply and Voltage Control from Generation Sources Service under Schedule 2 of the OATT
- 6345 – Revenues for Energy Imbalance Service under Schedule 4 of the OATT

- 6346 – Revenues for Cumulative Transmission Energy Losses. This is an inactive account.
- 6347 – Revenues for Residual Uplift under Schedule 10 of the OATT
- 6348 – Revenues for Non-Capital Support Charge Rate under Schedule 9 of the OATT

o. The table below shows Account 9400 (Amortization) broken down in the requested categories.

Asset Group	2017 Amortization
Borden Buildings	$ 16,268
Borden Equipment	13,765
Borden Turbines	626,383
CT3	799,257
CTGS Boilers	2,022,771
CTGS Buildings	842,419
CTGS Electrical Equipment	117,352
CTGS Turbines	1,777,120
Distribution	11,211,532
ECC	22,428
Misc Power Plant Equipment	105,751
Other	1,640,657
Transmission	2,176,982
Grand Total	**$ 21,372,683**

p. There are two components that make up the Balance of Account 9420 as shown in the table below:

Amortization of 2016 Customer Outreach Program as per Order UE 15-02	$144,222
Accrue payable to PEI Energy Corporation for DSM collected through rates	$178,254
Balance of account 9420 for 2017	$322,476

As discussed in Section 4.2.1, on November 3, 2015 the Commission issued Order UE15-02 with respect to the Company's 2015-2020 Demand Side Management Application filed on June 3, 2015. The Order approved annual expenditures of up to $167,500, commencing in 2016 with respect to public outreach and education only. In 2016, actual expenditures for this program totaled $144,222. As per the application, these costs were deferred and amortized in the year following, 2017.

Also discussed in Section 4.2.1, the General Rate Agreement approved by the Commission for the period March 1, 2016 to February 28, 2019 included a provision for the recovery of a potential new DSM program during the period. In anticipation of the PEI Energy Corporation's application for a Demand Side Management or Energy

Efficiency Program, at the end of 2017, an accrual was recorded for the $178,254 collected through rates based on the General Rate Agreement inputs for DSM.

On June 28, 2018, the PEI Energy Corporation filed an application with the Commission seeking approval of an Electricity Efficiency and Conservation Plan for the term 2018-2021 (Docket UE41400). The application sets out the PEI Energy Corporation's plan as well as proposed funding requirements from the provincial and federal governments as well as MECL and Summerside. Based on this filing, MECL accrued the balance of its funding obligation for 2018 as set out below:

PEI Energy Corporation Electricity Efficiency and Conservation Plan Docket 41400:	
Table 8 (Page 33) 2018 Target Funding from MECL & Summerside	$600,000
MECL Allocation based on GWh sales for 2018 - Table 7 (page 29)	90.1%
Total MECL Target funding for 2018/2019	$540,600
Accrued in 2017 above	$(178,254)
Balance of target funding accrued in 2018	$362,346

q. Schedule 6.0 includes the following costs to MECL for its use of the interconnection with New Brunswick:

Account 7040 $187,428 for O&M Murray Corner
Account 7041 $165,233 for O&M Memramcook
Account 7041 $183,878 for Breakers Rental Murray Corner
Account 7415 $122,565 for O&M Submarine Cables
Account 7415 $2,681,281 for Lease Payments for New Cables

The lease payment to the PEI Energy Corporation is $268,128.14 monthly and payments began on March 1, 2017.

A second cost component associated with the new submarine cables is New Brunswick Power's OATT Schedule 9 – Direct Assignment Charges for the new transmission lines from Memramcook to Cape Tormentine. The monthly charge is $96,727.72 and is recorded in Account 7415. Payments began in 2018 and no charges were included for 2017 in Schedule 6.0.

Also not included in Schedule 6.0 is the collection of $326,177 from MECL customers in 2017 for replenishment of the submarine cables contingency fund. For 2017 this was collected from customers through a rate rider on energy charges and remitted directly to the PEI Government. As such, it did not become an expense or revenue item for MECL. With the approval of MECL's OATT in 2018, this is now being recovered through OATT charges.

IR-16 With respect to Schedule 3.1 of the Chymko CAS, please reconcile the total revenue requirement of $182,601K shown in Schedule 3.1 to the 2017 revenue requirement of $192,535K provided in Schedule 14-4 of MECL's Application dated November 28, 2018.

Response

The following table reconciles the revenue requirement show in Schedule 3.1 of the Chymko Cost Allocation Study to Schedule 14-4 of MECL's Application:

Total Revenue Requirement Schedule 14-4 General Rate Application	$192,535,281
Less: Total Other Revenue (Schedule 14-5)	(9,924,289)
Less: Rate Code 610 Pole Rent Reallocated from Street Lighting Class to Other Revenue by Chymko Engineering	(10,170)
Total Electric Revenue Requirement Schedule 3.1 of Chymko CAS	**$182,600,822**

IR-17 Beginning with the costs by account as per Schedule 6.0, please derive the 2017 revenue requirement in the categories provided in Schedule 14-4 of MECL's Application dated November 28, 2018, except with the Operating Expenses broken down into the following categories:

a) Generation

b) Purchases from NB

c) Purchases from Wind

d) Other Purchases

e) Transmission (to reconcile to Schedule 9-1)

f) Distribution (to reconcile to Schedule 9-3)

g) T&D Other (to reconcile to Schedule 9-4)

h) General and Administrative (to reconcile to Schedule 10-1)

i) Corporate Services and Support (to reconcile to Schedule 10-2)

Response

An electronic file reconciling Table 6.0 of the CAS with Table 14-4 is provided in excel format. The file is called IR-17 – Attachment 1- MECL Cost Allocation Multeese.

The following table is a summary of this reconciliation:

Summary Table		
Generation		$ 4,121,159
Purchases from NB		86,573,305
Purchases from Wind		23,426,491
Other Purchases		4,344,174
ECAM		(2,358,689)
Transmission		7,493,351
Distribution		4,475,584
Transmission & Distribution - Other		2,055,983
General & Administrative excluding Corporate Services and Support	5,799,733	
General & Administrative - Corporate Services & Support	2,647,973	
Total General & Administrative		$ 8,447,706
Operating Expenses Net of ECAM - Schedule 14-4		$138,579,065
Interest Expense		12,251,808
Amortization - Fixed Assets		21,802,450
Amortization - DSM		327,676
Amortization - Lepreau		93,400
Income Tax Expense		6,130,460
Return on Equity		13,350,423
Total Revenue Requirement – Schedule 14-4		$192,535,281

IR-18 With respect to Schedule 3.1:

a) Is the OATT revenue shown on Line 31 a net of what MECL pays and receives under OATT?

b) Please provide a derivation of the OATT revenue shown on Line 31.

c) Why are the Energy Costs, which are functionalized as transmission (Row 7), and the Transmission costs which are functionalized as transmission (Rows 11 and 13) excluded from OATT?

Response

a. The $1,914,000 of Open Access Transmission Tariff (OATT) revenue shown on line 31 of Schedule 3.1 (and Schedule 3.0) of the 2017 Chymko Cost Allocation Study is the difference between the total of what was charged to all transmission users and what was charged to MECL as a transmission user. In other words, it is what was charged to all transmission users other than MECL.

The $1,914,000 is shown as negative number because the revenue received from the other transmission users was used to offset some of the cost of the transmission system that MECL's retail electricity customers would otherwise have paid for through rates.

b. The $1,914,000 of Open Access Transmission Tariff (OATT) revenue shown on line 31 of Schedule 3.1 (and Schedule 3.0) of the 2017 Chymko Cost Allocation Study is the difference between the total of what was charged in 2017 to all transmission users and what was charged to MECL as a transmission user. In other words, it is what was charged to all transmission users other than MECL.

For 2017, the charges under MECL's OATT were based on year 2005 costs, and had been approved by IRAC on an interim basis in 2009.

The derivation of the $1,914,000 is as follows:

	($ x 1000)
Total revenue from OATT charges in 2017	7,962
Less OATT revenue from MECL	6,048 (for Network service)
Revenue from other transmission users	1,914 (for Point-to-Point service)

c. On Schedule 3.1 of the 2017 Chymko Cost Allocation Study, the costs on lines 7, 11 and 13 that are functionalized as Transmission are not excluded from the OATT.

Schedule 3.0 of the Cost Allocation Study shows the full assignment of costs to the Transmission function, as summarized below.

	Transmission ($ x 1,000)
Gross revenue requirement (i.e. total cost)	14,252
OATT revenue (users other than MECL)	(1,914)
Other revenue	(47)
Net revenue requirement	12,290

The gross revenue requirement of $14,252,000 is the total cost for the transmission system in 2017. It includes the costs on lines 7, 11 and 13 that are functionalized as Transmission.

The $225,000 on line 13 is for OATT administration.

MECL is required to have updated OATT charges in effect by no later than August 1, 2021. Depending on the timing of the next Cost Allocation Study, it may be the 2017 Chymko Cost Allocation Study that forms the basis for the updated OATT charges. If that is the case, then the $14,252,000 total cost for the transmission system in 2017 will serve as the starting point for developing the updated OATT charges.

For 2017, the charges under MECL's OATT were based on year 2005 costs, and had been approved by IRAC on an interim basis in 2009.

IR-19 With respect to Schedule 4.0, please explain what is included in the Substations 1841 Account, why it is split between Transmission and Substations, and how the percentages assigned to each are derived.

Response

Fixed Asset Account 1841 – Transmission Substations includes the power transformers and the associated substation infrastructure (buildings, fences, grounding, structures, circuit breakers, reclosers, etc.) at all of MECL's substations that form part of or are connected to the transmission system.

For Open Access Transmission Tariff (OATT) purposes, account 1841 is split between OATT related assets (assigned to the Transmission function) and non-OATT related assets (assigned to the Substations function) in the Chymko Cost Allocation Study. In the Study, all costs associated with providing transmission service under the OATT are included in the Transmission function, which can then serve as the starting point for development of OATT charges.

The assets assigned to the "Substations" function are the distribution substations. They are used for the transformation from transmission voltage (138 kV or 69 kV) directly to a distribution voltage (12.5 kV, 13.8 kV or 25 kV) for the purpose of supplying distribution system load.

In addition to distribution substations, MECL has substations centered around 138 kV/69 kV transformers. These transformers connect between the 138 kV and 69 kV portions of the transmission system. These are transmission substations and are included with the "Transmission" function in Schedule 4.0.

The percentages used to split Account 1841 assets between Transmission and Substations are:

- 71.6% to Transmission; and
- 28.4% to Substations.

These percentages were derived during past Cost Allocation Studies. MECL has recently added several new stations – in both the 'Transmission' and 'Substation' categories – and has plans to add at least two more in the 'Substation' category in the next few years to meet increasing customer demand and energy needs. MECL intends to revisit the Transmission/Substation split in the next Cost Allocation Study.

IR-20 With respect to Schedule 3.0, please identify any revenue requirement associated with transmission portion of Substations 1841 Account and explain where is included in Schedule 3.0.

Response

The Transmission portion of Fixed Asset Account 1841 is $21,173,000, and is included in the $22,055,000 for the Transmission function on line 9 of Schedule 3.4 – Functionalized Rate Base, as shown in the following table.

Assignment of Account 1841				
Account		**Total ($ x 1,000)**	**Transmission function ($ x 1,000)**	**Substations function ($ x 1,000)**
1841	Trans Sub Equip, Bldgs & Structures:			
	Gross fixed assets	48,014		
	Less accumulated amortization	17,051		
		30,963		
	Less Work In Progress	1,380		
	Net fixed assets (mid-year)	29,583		
	Allocation percentages	100.0	71.6	28.4
	Allocated net fixed assets	29,583	21,173	8,410
	Plus direct allocation:			
1740	Distribution Substation Land			5
1741	Distr Sub Equip, Bldgs & Structures			3,216
1744	Distribution Land			5
1840	Transmission Substation Land		451	
1844	Transmission Land		431	
	Less accumulated amortizn for 1741			(747)
	Total (Line 9 on Schedule 3.4)		22,055	10,889

The total rate base for the Transmission function is $ 55,281,000 (bottom line on Schedule 3.4). On Schedule 3.0 the revenue requirement associated with the Transmission function rate base is shown as:

- $2,491,000 for amortization expense;
- $1,929,000 for financing expense;
- $935,000 for income taxes; and
- $2,036,000 for net earnings.

The revenue requirement associated with the $21,173,000 is included in the above amounts.

IR-21 With respect to Schedule 3.0 of the Chymko CAS:

a) Please describe the function of the substations that drive the costs included in "Substations" and explain why these costs are classified as 100% Demand.

b) Please identify the dollar amounts associated with any substation (or portion of substation) whose function is not Distribution related.

c) If any portion of Substations is transmission, please explain why it is not included in OATT.

Response

a. The "Substations" function is the transformation from transmission voltage (138 kV or 69 kV) directly to a distribution voltage (12.5 kV, 13.8 kV or 25 kV) for the purpose of supplying distribution system load. It includes power transformers and the associated substation infrastructure (fences, grounding, structure, reclosers, etc.).

Substations are classified as 100% Demand-related (i.e. no Site, or Customer, related component) because generally the connection of one more customer to the system will not result in a requirement for a new or larger substation.

In the flow of electricity from generators, through the transmission system, to distribution substations, and then through distribution lines toward customers premises, it is starting at the "Primary Lines" function (i.e. the distribution lines) that it can readily be seen that the connection of one more customer to the system may result in a requirement to add to the system – likely a need to extend the length of a distribution line. Thus Primary Lines are classified as partly Demand-related (costs driven by the size of the load) and partly Site-related (costs driven by number of customers).

b. The "Substations" function in Schedule 3.0 includes only distribution related substations.

In addition to distribution substations, MECL has substations centered around 138 kV/69 kV transformers. These are transmission substations, and are included with the "Transmission" function in Schedule 3.0.

Transmission substations are part of MECL's Open Access Transmission Tariff (OATT) facilities.

c. The "Substations" function in Schedule 3.0 includes only distribution related substations.

IR-22 With respect to Schedule 2.2 of the Chymko CAS:

a) What are the units associated with the "Site Allocator Weighting Assumptions" shown in Rows 6 – 10, and how were the numbers in Rows 6 -10 determined?

b) Please provide the derivation of the "Base Allocators" in Rows 15 – 21.

Response

a. The units for Rows 6 and 7 are dollars. Service Lines (Row 6) is based on the average cost of supply and installation of service wire to a customer in each rate class in 2017. Meter Assets (Row 7) is the average unit cost per meter for each rate class in 2017.

The units for Rows 8 – 10 are a weighting multiplier applied to the monthly average number of sites. The base for this multiplier is the average number of bills per site per year to account for seasonal billing (12 bills per year for a non-seasonal customer; 6 or 7 bills per year for a seasonal customer). On top of the base multiplier, the following factors are applied:

Meter Reading (Row 8)

- Large industrial meter reading is given an additional 5× weight for the additional effort involved to collect and process meter data associated with the unique meters employed for this rate class (12 x 5 = 60).
- Lighting and unmetered is given zero weight for meter reading as there are no actual meters attached with those accounts. The monthly energy consumptions for that rate class are calculated based on known connected load and hours of use.

Billing (Row 9)

- Large industrial and Unmetered billing are given an additional 25× weight to represent additional effort associated with manual billing (12 x 25 = 300).
- Lighting is given 1/12× weight (thus offsetting the average number of bills per site per year) for billing because bills are calculated more akin to a rental contract and the monthly invoice amount is known well in advance (12 x 1/12 = 1).

Remittance & Collection (Row 10)

- Lighting is given 1/12× weight for remittance and collection because uncollectable accounts are less prevalent (12 x 1/12 = 1).

b. The "Base Allocators" in Rows 15 – 21 were generally derived in a top-down approach, starting with metered sales and demand data.

The Residential, Residential seasonal (S) and General Service allocators were determined by applying load and coincidence factors to those rate classes' sales figures to estimate their coincident and non-coincident peak loads. The load and coincidence factors were determined during a previous load study. The Residential and Residential seasonal (S) rate classes were further adjusted by separating out the farm accounts, as further explained in the response to IR-24 a).

The Large Industrial figures were derived from hourly metered data. Several Small Industrial customers transitioned to Large Industrial in 2018. The Large Industrial and Small Industrial allocators were adjusted to reflect the impact of those transitioned customers on their new rate class. This ensures that the rates being developed from the Cost Allocation Study reflect future system usage by each rate class.

The Lights demand figures were based on the number of lights in service, multiplied by the power consumption of each light. The energy consumption was further derived based on the settings for duration of operation.

The Small Industrial energy and demand figures were measured. As mentioned above, several Small Industrial customers moved to the Large Industrial rate class in 2018. The figures in Columns G and H were adjusted to reflect this.

The Unmetered figures were determined by an estimation of the unmetered load in the service area.

The difference between the 1CP – Input (Row 15), 1CP – Transmission (Row 17) and 1CP – Distribution (Row 18) figures can be attributed to system losses. These were broken down into Transmission and Distribution system losses, and were derived by determining the difference between system inputs and outputs.

The 1CP – Input Firm (Row 16) is lower than 1CP – Input Firm (Row 15) by the amount of interruptible contracts that are in place.

IR-23 With respect to Schedule 5.1:

a) Please confirm that the Exogenous Allocators are based on MECL professional judgement. If this is not the case, please provide their derivation.

b) Please identify any other allocators that are based on MECL judgement.

Response

a. Confirmed.

b. Functional allocators based on professional judgement are found in Rows 6 – 10 of Schedule 5.1 as well as on Schedule 5.2 in Rows 6 – 12, 31 – 32, 42 – 44 and 56 – 61. All input assumptions are formatted in blue font.

IR-24 With respect to Schedule 2.3:

a) What is the purpose of this Schedule?

b) Please explain this schedule, demonstrating how its purpose is achieved.

c) What is the source of the data used in this Schedule?

Response

a. The purpose of Schedule 2.3 of the spreadsheet model is to allow the user to switch cost allocation results between two scenarios: Farm as a separate (proposed) rate class; and status quo, where farms are interspersed between residential and seasonal residential rate classes.

Each customer in MECL's billing system has a Standard Industrial Classification (SIC) code that was assigned by the Company. This practice was begun in the mid-1980s to facilitate responding to government data requests in regard to customer groupings that did not align with the Company's rate classes. Residential customers with a farm SIC code were put in the Residential "farm" class for the purposes of the Cost Allocation Study.

b. To switch between scenarios described in part (a), the user should select "STATUS QUO RATE CLASSES" from the drop-down menu located in cell A8 of the "Index" Schedule in the electronic spreadsheet version of the schedules.

c. See response to see IR-22.

IR's 25 – 54 are Questions related to MECL's November 28 Filing

IR-25 With respect to outstanding costs under the Energy Accord, It is noted on page 15 that PEI Energy Corporation intends to restructure the financing with fixed repayment terms, and it is proposed "that the fixed repayment amounts charged to customers for costs recoverable on behalf of the Province should, subject to Commission approval, be recovered as an energy related cost as opposed to a rider on customers' bills. This will eliminate the variability in the monthly repayment amount associated with a rate rider based on monthly consumption levels." It is further proposed (page 16) that these costs "would be recovered through the Energy Cost Adjustment Mechanism". Please elaborate on how the inclusion of these costs in ECAM eliminates the variability in the monthly repayment amount.

Response

Under the current provisions of the debt collection agreement, MECL is collecting a per kWh charge of $0.00536 for deferred energy charges on behalf of the PEI Energy Corporation. Because of the variability and seasonality of kWh sales, this results in considerable variations in the monthly collections and remittances to the PEI Energy Corporation. It is the PEI Energy Corporation's intent to refinance the debt with fixed payment terms. To match the PEI Energy Corporation's fixed monthly payments under its planned refinancing, the PEI Energy Corporation has asked MECL to make fixed monthly remittances to the PEI Energy Corporation. It is this refinancing that is the cause of removing the variability in the monthly payment amount, not its inclusion in ECAM.

IR-26 With respect to Schedule 4-2 on page 16, it is noted that these costs relate to "deferred energy costs associated with the closure of Dalhousie and the refurbishment of Point Lepreau". Please explain how the proposal to recover these costs through ECAM is consistent with the Company's proposal to classify 25% of Lepreau as Demand.

Response

There is no inconsistency. Although described on page 16 as "deferred energy costs", these costs are actually a combination of Demand-related and Energy-related costs associated with the Dalhousie and Point Lepreau participations in the past, and should more accurately be referred to as simply "deferred costs".

In principle, these deferred costs could be separated into Demand-related and Energy-related components, and recovered through adders to the demand charges and energy charges under the various rate classes. However, as a practical matter, these deferred costs are recovered through ECAM (Energy Cost Adjustment Mechanism); i.e. as a component of the energy charges for all rate classes, because most of MECL's customers do not pay demand charges. (There is no demand charge in the Residential, Street lighting or Unmetered Rates and General Service customers with less than 20 kW of monthly metered demand do not incur a demand charge.)

IR-27 With respect to the Weather Normalization Reserve as discussed in Section 5.2, please describe how the balance shown in Appendix 5, Schedule 4 is being applied to customer rates in this proceeding. If the balance is not affecting the proposed rates, please explain why not.

Response

The balance in the weather normalization account discussed in Section 5.2 is not being applied to customer rates at this time. In its original application for the Weather Normalization in Section 7.2 of the Rate Application filed on October 21, 2015 on page 24, the Company states that:

> *Conceptually, the balance in the Weather Normalization Reserve on the Company's balance sheet will represent the cumulative change in contribution from sales resulting from variations in HDD from normal and should, over time, net to zero (contribution equals revenue from additional kWh sales minus the cost of purchasing additional kWh sales or marginal net revenue times the additional kWh sales). As illustrated on an annual basis in Schedule 1 of Appendix 6, in a year when HDD are higher than normal (2013 and 2014), an amount will be subtracted from the Company's earnings before income taxes and added to the Reserve. When HDD are lower than normal (2010 – 2012), an amount will be added to the Company's earnings before income taxes and subtracted from the Reserve. Over the ten year period, the variation from average HDD balances to zero as does the balance in the reserve account. Thus, there would be no need for an automatic adjustment mechanism to deal with Reserve balances.*

The WNRA was approved by the Commission on an interim basis in Order UE16-04 and the Commission has continued to monitor the account on an annual basis through updates to the components of the reserve. It is the Company's opinion that the balance in this account (see Appendix 5 – Schedule 4 of the General Rate Application) does not warrant collection through rates at this time.

IR-28 With respect to Schedule 8-3, page 45, please provide a table showing the contribution of each generation unit and purchase agreement to the supply of the NPP for the years 2017 and 2020. For purchases, please show the purchase under each agreement separately.

Response

THIS RESPONSE WILL BE PROVIDED ON A CONFIDENTIAL BASIS UPON RECEIPT OF AN EXECUTED NON-DISCLOSURE AGREEMENT.

IR-29 With respect to Schedule 8-4, page 46, please provide a copy of the purchase agreements associated with each purchase from New Brunswick.

Response

THIS RESPONSE WILL BE PROVIDED ON A CONFIDENTIAL BASIS UPON RECEIPT OF AN EXECUTED NON-DISCLOSURE AGREEMENT.

IR-30 With respect to Schedule 8-4, page 46, please provide the derivation of the costs shown for each of the following for each of the years 2017 - 2021:

a) Point Lepreau

b) Energy Purchase Agreement – Firm Energy Purchases

c) Energy Purchase Agreement – System Energy Purchases (with Secure Energy and Assured Energy shown separately)

d) Wind

For each of the above, please provide:

- The annual energy purchased and the average price of that energy
- The portion of the costs that arises because of the purchase of capacity

Response

THIS RESPONSE WILL BE PROVIDED ON A CONFIDENTIAL BASIS UPON RECEIPT OF AN EXECUTED NON-DISCLOSURE AGREEMENT.

IR-31 With respect to Schedule 8-4, page 46, please explain why Firm Energy Purchases under the Energy Purchase Agreement increase significantly over the years shown while the System Energy Purchases decline significantly.

Response

There are two reasons why Firm Energy Purchases have increased while System Energy Purchases have decreased. One is related to growth in load, and the other is related to availability of firm transmission capacity.

The growth in load has required MECL to purchase additional generating capacity from NBEM. As a result, MECL can treat more System Energy purchases as Firm since MECL can use the generating capacity purchased from NBEM to backstop these energy purchases.

In addition, MECL requires firm transmission in order to deliver Firm Energy and generating capacity. There is currently 300 MW of firm transmission capacity across the NB-NS/PEI interface. NBEM has rights to all firm transmission across the NB-NS/PEI interface that is not otherwise assigned to MECL, as can be seen below:

- MECL – Point Lepreau participation – 30 MW
- MECL – Carryover of Dalhousie participation – 20 MW
- MECL – International Power Line (IPL) redirect & reassignment – 30 MW
- NBEM – procured on behalf of MECL in March 2016 – 50 MW
- NBEM – procured during NBSO Open Season (Summer 2016) – 70 MW
- NBEM – procured during NBSO Open Season (February 2017) – 100 MW

Prior to 2016, MECL was limited to 50 MW of Firm Energy and capacity purchases (in addition to its Point Lepreau participation) due to firm transmission limitations in New Brunswick. However, since 2016 MECL has been able to procure up to 220 MW of additional firm transmission through MECL's 50 MW (2016) and NBEM's 170 MW (2016-17).

It is this additional firm transmission in NB that has allowed MECL to procure the firm generating capacity, and with it Firm Energy, off-Island in lieu of building on-Island generation. As the Firm Energy purchases have increased, the System Energy purchases have decreased.

IR-32 The discussion of Assured Energy on pages 47 notes that it is backed up by the Charlottetown GS (55MW) and by Borden-Carleton (40MW). However, page 48 states that from November – March, this backup will be supplied by Borden-Carleton only. Please clarify the role of each plant in providing backup. Are both plants ever providing backup simultaneously?

Response

In past EPAs, the CTGS has backed up the Assured Energy purchases for the entire year. There are two periods in the EPA; the "Summer Period" from April 1st to October 31st, and the "Winter Period" from November 1st to March 31st.

The previous EPA Winter Notification Period was ninety-six (96) hours in November, February and March and forty-eight (48) hours in December and January. The Summer Notification Period was seven (7) calendar days. NBEM would backstop the energy during the Notification Period and MECL would be responsible for backstopping the energy product beyond the Notification Period.

With the CTGS's proposed decommissioning on December 31, 2021 and the reduced compliment of CTGS operating personnel, it was necessary to increase the length of the Notification Period to 90 days. NBEM agreed to backstop the CTGS during the "Summer Period" but not during the "Winter Period". MECL decided to use the Borden Generating Station (BGS) totaling 40 MW to backstop the Assured Energy product during the Winter Period for the first 90 days, and CTGS would backstop the product in the event the backstop is required beyond the 90 days. During the "Winter Period" MECL will have to purchase 10 Minute & 30 Minute Supplementary Non-Spinning Reserve from the NBP-SO.

IR-33 With respect to Schedule 8-8, page 51, please provide a copy of the purchase agreements associated with purchase of wind energy.

Response

THIS RESPONSE WILL BE PROVIDED ON A CONFIDENTIAL BASIS UPON RECEIPT OF AN EXECUTED NON-DISCLOSURE AGREEMENT.

IR-34 Page 51 notes that purchases from 79MW of wind are based on prices 'comparable to the Minimum Purchase Price Regulations under the Renewable Energy Act". Please provide the minimum purchase price effective April 1, 20017, and show how it was developed based on the Minimum Purchase Price Regulations.

Response

The *Renewable Energy Act – Minimum Purchase Price Regulations* states, in part, the following:

"3. Adjustment, wind energy project

The minimum purchase price established under subsection (1) shall be adjusted on April 1, 2008 and April 1 thereafter by using the following formula:

A + (B x C)

Where A = mpp, B = CPI, C = operating cost"

In this case, A (`mpp` or minimum purchase price) is $0.0575, B (CPI) is determined annually based on Statistics Canada data, and the C (the operating cost) is $0.02.

In effect, the Regulations set the minimum purchase price based on a fixed amount of $0.0575, plus an operating amount that increases based on CPI. The CPI figure has been cumulative since 2006, and as of 2016 the figure of B x C stood at $0.023172.

Below are the tables showing how the minimum purchase price rate was calculated in 2017 and 2018:

2016 rate			**0.080672**	**Starting April 1, 2016**
CPI				
Avg. year ending	Dec-15	129.3		
Avg. year ending	Dec-16	130.8	1.011601	increase
	0.023172 x 1.011601 =		0.023441	
		fixed rate	0.0575	
2017 rate			**0.080941**	**Starting April 1, 2017**

2017 rate			**0.080941**	**Starting April 1, 2017**
CPI				
Avg. year ending	Dec-16	130.8		
Avg. year ending	Dec-17	133.2	1.018349	increase
	0.023441 x 1.018349 =		0.023871	
		fixed rate	0.0575	
2018 rate			**0.081371**	**Starting April 1, 2018**

IR-35 With respect to Schedule 9-2 (page 58), please reconcile the OATT expenses for 2017 to the OATT expenses in Schedule 6.0 of the Chymko CAS.

Response

The following tables reconcile Table 9-2 to the appropriate accounts in Schedule 6.0 of the Chymko CAS:

SCHEDULE 9-2	
MECL OATT Expenses ($)	
Description	**2017 Actual**
Network Service	$ 5,304,673
Schedule 1	210,292
Schedule 2	340,020
Schedule 3C	9,737
Schedule 4	108,068
Schedule 9	74,928
Schedule 10	-
OATT Operations	225,185
Total	**$ 6,272,903**

Chymko Cost of Service Study		
Schedule 6.0 - Revenue Requirement 2017		
OATT Expenses		
Account	**Description**	**2017 Trial Balance**
7500	Transmission Access	$ 5,304,673
7502	Scheduling Service	210,292
7503	Wind Regulation and Load Following	9,737
7504	Reactive Supply and Voltage Co	340,020
7505	Energy Imbalance OATT	108,068
7507	Residual Uplift	-
7508	Non-Capital Support Charge	74,928
7510	OATT	225,185
	Total	**$ 6,272,903**

IR-36 At page 127, the Company proposes two changes within the Residential class, both of which are said to be "based on the results of the 2017 CAS". Please elaborate on how each change is based on the 2017 CAS results.

Response

The Company has proposed two changes to the Residential class rate design. The first is the proposal to combine the Urban and Rural residential customers into one rate class for all year round residential customers set a the currently approved rate of $24.57 per month for rate code 110. As discussed on Page 129 of the rate application, Table 12 of the CAS provides a calculation of the unit cost results for consideration in rate design. As Chymko states in Paragraph 84 of the 2017 CAS:

> *Site related unit cost gives some indication for an appropriate service charge. Given that the service line, meter, and billing costs are all considered site related, a monthly service charge equal to the unit cost would at least ensure the utility is recovering the localized fixed costs from every customer regardless of their consumption.*

The Residential site related monthly cost calculated by Chymko in the 2017 CAS is $24.61 per month which is substantively the same as the current monthly charge for Residential Urban customers of $24.57 per month.

In Table 11 of the CAS, the 2017 revenue to cost ratio for residential customers is calculated at 91%. Reducing the rural residential service charge will serve to reduce that ratio further to 89%. In order to improve the revenue to cost ratio for residential customers, the Company is proposing to phase out the residential second block beginning with an increase from 2,000 kWh to 5,000 kWh on March 1, 2021 followed by the elimination of the second block on March 1, 2022. This is being proposed to improve the revenue to cost ratio for residential customers. As shown in Schedule 13-12 of the General Rate Application, the revised revenue to cost ratio after the increase in the second block to 5,000 kWh will be 91%. The eventual elimination of the second block will serve to improve the RTC even further.

IR-37 It is noted at Page 128, last paragraph that "with changes in meter reading technology and increases in customer density throughout PEI" the cost difference between urban and rural is "no longer considered material".

a) Please identify the components of the cost that are included in the monthly service charge?

b) Please provide any tracking of costs or other analysis done by MECL to reach its conclusion that the difference in service cost for urban and rural is now immaterial.

Response

a. The purpose of the monthly service charge in the Residential Rate is to recover site related costs. The table below shows the site related costs that were allocated to the Residential Rate in the Chymko 2017 Cost Allocation Study (Schedule 1.4). The resulting $/month amount of allocated costs then provides guidance as to an appropriate amount for the monthly service charge.

Chymko 2017 Cost Allocation Study			
	Allocation of site related costs ($ x 1,000)		
	Residential	Residential (Seasonal)	Residential (Farms)
Generation	0	0	0
Purchased Power	0	0	0
Transmission	0	0	0
Substations	0	0	0
Primary Lines	5,204	682	190
Transformers	3,049	399	111
Secondary Lines	1,802	236	66
Service Lines	4,400	683	161
Meter Assets	955	125	35
Meter Reading	655	49	24
Billing	721	54	26
Remittance and Collection	523	39	19
Uncollectibles and Damage Claims	357	47	13
Service Connections	'- 266	'- 27	'- 10
Late Payments	'- 485	'- 15	'- 18
Lighting	0	0	0
Total	16,915	2,272	619
Total Number of Monthly Bills in 2017	687,432	51,438	25,128
Average site related cost ($/month)	**24.61**	**44.17**	**24.63**

The average $44.17/month for Residential Seasonal cannot be compared directly with the corresponding values for Residential and Residential Farms because most Seasonal customers receive only six bills per year. The monthly service charge for Residential Seasonal customers who choose to minimize their electricity use during off-season is $37.50/ month, which reflects the need to recover site related costs through six bills per year.

b. MECL does not track urban and rural costs separately. Other than the different service charges for Urban and Rural under the Residential Rate, all of MECL's rates are common throughout the Company's service territory. Since the 2017 Cost Allocation Study shows site related costs for Residential that are essentially the same as the existing Residential Urban service charge, the Company is proposing to make the Residential Rural service charge the same as the Urban service charge. As a matter of policy, this will remove the last distinction between urban and rural in the Company's rates.

IR-38 Please provide copies of MECL's input to PEIEC with respect to its EE&C Plan (Docket UE 41400), as referenced on page 131, paragraph 2.

Response

The PEI Energy Corporation retained EfficiencyOne of Nova Scotia to assist PEI Energy Corporation in developing an EE&C Plan.

MECL's input with respect to the EE&C Plan included the following:

- MECL's June 2015 Demand Side Management and Energy Conservation Plan. EfficiencyOne used this as a source of information that was already in the public domain. A copy of the Application is attached as IR-38 - Attachment 1;

- An April 2017 presentation given by MECL to the PEI Energy Corporation in regard to cost effectiveness testing and the potential impact on electricity rates of achieving an incremental annual energy saving equal to 2% of electricity sales. A copy of the presentation is attached as IR-38 - Attachment 2;

- MECL's energy sales by rate class (historical and forecast). This was first provided on Oct 24, 2017 and then updated on June 6, 2018. A copy of the sales forecast provided to the PEI Energy Corporation is attached as IR-38 - Attachment 3;

- Information on system losses and MECL's weighted average cost of capital. This was provided in an e-mail thread culminating on November 22, 2017. A copy of the email is attached as IR-38 - Attachment 4;

- MECL's comments on the EE&C Plan. These were filed with IRAC on August 29, 2018. A copy of the comments filed with Commission are attached as IR-38 - Attachment 5;

- In early December 2018 MECL provided responses to three Information Requests from Synapse to the PEI Energy Corporation in regard to the PEI Energy Corporation's application to IRAC for approval of its EE&C Plan. Synapse was retained by IRAC to assist with evaluating the PEI Energy Corporation EE&C Plan. A copy of the responses to the Synapse IRs as well as the email threads from MECL Counsel to both Commission and PEI Energy Corporation counsel are provided as IR-38 - Attachment 6.

IR-39 As noted at Page 131, paragraph 2, MECL proposes to “gather the data necessary to develop consumption and rate mitigation solutions” through “the load and consumption study for farms, as well as the proposed Load Research Study”. Has this been done? If not, when will it be done, and on what basis were the customer impacts (as shown in this Application) determined? How does it relate to Schedule 13-9 on page 133?

Response

Paragraph 2 on Page 131 refers to two studies.

The purpose of the farm rate study is to identify an appropriate alternative rate class for the large farms that are now served under the Residential Rate. If left on the Residential Rate when the second energy block is eliminated, these farms would experience potentially large electricity bill increases.

The farm rate study is underway. MECL is currently collecting hourly load data for 88 of the larger farms in PEI for the purpose of estimating the size and timing of farm peak loads relative to the system peak load. The Company operates under cost of service regulation, which means that the rates are intended to recover the cost of providing electricity service. The first step in identifying or developing an appropriate rate for a group of customers is to estimate the cost of providing service to those customers, which is in part based on the size and timing of their peak loads relative to the system peak load.

The Company placed an order for the meters in October 2017. However, delivery was delayed due to delays by the manufacturer in obtaining components from its sub-suppliers. The last batch of meters was received from the manufacturer in May 2018, and installed in June. Thus July 2018 is the first month with a complete set of hourly data.

At least one full year of data is needed for analysis, so a draft report is not expected to be available until Fall 2019 at the earliest.

The Load Research Study will get underway in 2019. The purpose of this study is to collect hourly load data for a representative sample of Residential and General Service customers, so as to improve on the estimates of the size and timing of the peak loads of these rate classes for future Cost Allocation Studies. The expectation is that better estimates of the size and timing of peaks loads for the Residential and General Service classes will result in increased confidence in future Cost Allocation Study results.

The Load Research Study will involve collecting data for a total of approximately 600 customers over a period of two years. Further description of the Load Research Study is provided in the response to IR-44.

IR-40 Further to Schedule 13-9, please provide the number of customers whose monthly consumption, averaged over a year, falls within the following ranges: 1-200kWh, 201-400kWh, 401-500kWh, 501-600kWk, 601-700kWh, 701-800kWh, 801-900kWh, 901-1000kWh, 1001 -1200kWh, 1201-1500kWh, 1501-2000kWh.

Response

The following table shows the number of residential customers whose average monthly consumption falls in the range category indicated:

Monthly Average Consumption Range	Customer Count
1 - 200 kWh	5,049
201 - 400 kWh	9,136
401 - 500 kWh	5,356
501 - 600 kWh	5,481
601 - 700 kWh	4,914
701 - 800 kWh	4,182
801 - 900 kWh	3,428
901 - 1000 kWh	2,662
1001 - 1200 kwh	4,064
1201 - 1500 KWh	3,845
1501 - 2000 kWh	2,911
Grand Total	**51,028**

IR-41 The Company notes on page 138 that with only six months of data accumulated to date, it is "not in a position to provide conclusive recommendations to the Commission (or farm customers) with respect to the recommended rate classification and resulting rates for farm customers".

a) Which months of data does the Company currently have?

b) What is the source of the data currently being used by the Company in its cost allocation study to assign costs to the farm class?

c) Based on the data currently available, does the Company have any preliminary indication of the rate class (or classes) into which farms might reasonably fit? If not, please explain why not?

d) Is the Company of the view that if farms are assigned to a new class, all farms will move to the same class? If yes, what is the most likely class? If not, to which classes might farms be assigned?

e) Does the Company anticipate that any farms will remain in the Residential class?

f) Based on the information currently available, what effect would the addition of all farms to the General Service class have on the R/C ratio of that class?

g) Based on the information currently available, what effect would the addition of all farms to the Small Industrial class have on the R/C ratio of that class?

Response

a. At the beginning of 2019, MECL had six months of complete hourly load data.

The Company placed an order for the meters to be used for the farm rate study in October 2017. However, delivery was delayed due to delays by the manufacturer in obtaining components from its sub-suppliers. A few meters were received and installed in February 2018. However, the last batch of meters was received from the manufacturer in May 2018, and installed in June. Thus July 2018 is the first month with a complete set of hourly data for all the farms in the study.

b. Each customer in MECL's billing system has a Standard Industrial Classification (SIC) code that was assigned by the Company. This practice was begun in the mid-1980s to facilitate responding to government data requests in regard to customer groupings that did not align with the Company's rate classes. Residential customers with a farm SIC code were put in the Residential "farm" class for the purposes of the Cost Allocation Study.

c. There is currently insufficient data to provide a preliminary indication of the appropriate rate class for the larger farms. MECL believes that it would be appropriate for small farms to remain in the Residential class if that is advantageous for them. This view for small farms is further discussed in e) following.

d. MECL currently provides electricity service under the following rate classes:

- Residential (including Seasonal);
- General Service (including Seasonal);
- Small Industrial;
- Large Industrial;
- Street and Area Lighting; and
- Unmetered.

If farms are moved from the Residential class, the most likely options are to create a new rate class just for farms or to move them to either General Service or Small Industrial.

MECL believes that it would be appropriate for small farms to remain in the Residential class. This is further discussed in the response to e) next.

e. MECL believes that it would be appropriate for small farms to remain in the Residential class.

Prior to the adoption of NB Power rates + 10% in 1998 as part of price cap regulation, small farms were eligible for service under MECL's Rural Residential Rate. The criteria were as follows:

"A farm may be considered a residential customer if it has an occupied domestic residence and may be served through a single meter at this rate. Service supplied at this rate shall be single-phase to a maximum service entrance capacity of 200 amperes to each individual residence or household. Load requirements in excess of this capacity shall be served under the General Service Rate."

Most family mixed farms met these criteria and were served as Residential customers.

Farms were eligible for service Under NB Power's Residential Rate, but with no limit on the size of the load to be served. Since 1998, the size of the larger farms has increased to the point that their electricity load greatly exceeds that of even the largest of homes, with most of their electricity usage being billed at the second block energy charge; i.e. their load is much larger than 2,000 kWh/month.

However, MECL believes that many of the customers that are identified as farms in the Company's billing system would meet the pre-1998 criteria for service under the Residential Rate. The Company's Residential Rate currently allows for a customer to operate a small business out of their home, with the electricity for the business operation delivered through the one meter for the house, and included with the domestic electricity usage for billing purposes. The Company believes that it would be appropriate to continue to make a similar arrangement available to small farms, perhaps in keeping with the pre-1998 criteria.

f. 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 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

g. 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% without Farms to 94% with Farms.

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

IR-42 With respect to Schedule 13-12:

a) Please confirm that there is a two year timing difference between the effective dates of the proposed service charge reduction to rural customers and the proposed increase of first block energy to 5000kWh.

b) If a) is confirmed, please provide the estimated R/C for Residential for the two years between the reduction of the service charge and the change to the energy blocks.

Response

a. Yes, there is a two year timing difference between the effective dates of the proposed service charge reduction for rural customers and the proposed increase in the first block energy to 5,000 kWh.

b. The following table shows the revised revenue to cost ratios for 2019 and 2020:

Reduction in Rural Service Charge			
Urban Service Charge Rate per Month		24.57	
Rural Service Charge per Month		(26.92)	
Reduction in Monthly Service Charge for Rural Customers		(2.35)	
Number of Rural Bills Issued in 2017		421,154	
Annual Reduction in Residential Rate Class Revenue		(989,712)	
Impact 2019 - March 1 to December 31, 2019 (10 Months)		(825,000)	
Impact 2020 - Full Year		(990,000)	
2019 Impact on RTC:	**2017 Actual CAS**	**Incremental Revenue**	**2017 Revised**
Revenue ($ millions)	52.1	(0.825)	51.3
Cost ($ millions)	57.4		57.4
Revenue to Cost Ratio	90.8		89.3
2020 Impact on RTC:	**2017 Actual CAS**	**Incremental Revenue**	**2017 Revised**
Revenue ($ millions)	52.1	(0.990)	51.1
Cost ($ millions)	57.4		57.4
Revenue to Cost Ratio	90.8		89.0

IR-43 Please provide calculations (preferably in Excel format with all formulae intact) supporting Schedules 13-13 and 13-14.

Response

Response submitted electronically as an Excel Workbook Multeese IR #43 13-13 & 13-14.xlsx.

IR-44 With respect to the last paragraph on Page 141, please provide details of the expanded Bridge Meter project expansion, as filed in Docket UE20728 (2019 Capital Budget).

Response

MECL 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, MECL 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 is not known and cannot be measured directly. This is the case for the Residential customer class, and small General Service customers which together represent approximately 80% of MECL'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.

To provide more up-to-date input for the next cost allocation study (expected to be based on revenues and costs for 2020), the Company will collect hourly load data for a sample of Residential and General Service customers beginning in 2019 and continuing through 2020. The number of customers needed to obtain statistically significant results is estimated as 600, with approximately one third being Residential and two thirds being General Service.

To undertake this load research, MECL will install 600 Bridge meters on a random selection of Residential and General Service customers. These meters store hourly load data, which will be downloaded monthly by the Company's meter readers.

IR-45 At Section 13.4.2 at pages 141 and 142, the Company discusses the General Service class and notes that its planned studies with respect to farms will likely impact this class. However, no such discussion is included with respect to the Small Industrial class. Has the Company concluded that no farms could be transferred to the Small Industrial class? If so, on what basis has this conclusion been reached?

Response

MECL has come to no conclusions about the movement of farms to the Small Industrial class.

The discussion about the impact of moving farms to the General Service class is part of a larger explanation of why the Company has not proposed to begin the process of moving the General Service class toward the target range for Revenue to Cost ratios. The Small Industrial class has a Revenue to Cost ratio of 102%, which is well within the target range, and thus there is no corresponding discussion in regard to the Small Industrial class.

IR-46 With respect to Schedule 14-4 at page 153, please reconcile the 2017 Operating Expenses of $135,579,065 with the sum of the 2017 costs provided in Sections 8, 9 and 10.

Response

Please note that the total operating costs (net of ECAM) in Schedule 14-4 is actually $138,579,065 not $135,579,065 as presented in the question.

The table below shows the derivation of the operating costs from the costs provided in Sections 8, 9 and 10. Please note the amortization of the Lepreau Writedown and DSM, which are included in the Energy Costs in Section 8, are shown separately below operating costs in Schedule 14-4.

SCHEDULE 14-2		
Operating Expenses ($)		
	Schedule Reference	**2017 Actual**
Energy Supply Expenses	8-3	$ 18,105,056
Energy Supply Expenses - Other	8-8	781,150
ECAM		(2,358,689)
Distribution	9-3	4,475,585
Transmission*	9-1	7,493,351
Transmission & Distribution - Other	9-4	2,055,982
General & Administrative **	10-4	8,447,706
Total Operating Expenses	14-2	139,000,141
Less: Amortization of Deferred Charges in ECAM (see below)	8-3 (Line 13)	421,076
Total Operating Expenses (Net of ECAM)	14-4 (Line 1)	$ 138,579,065

Amortization - DSM Costs	Schedule 14-4 Line 4	$ 327,676
Amortization - Lepreau Writedown	Schedule 14-4 Line 5	93,400
Total Amortization of Deferred Charges in ECAM		$ 421,076

IR-47 With respect to Schedule 14-5 at page 154:

a) Please provide a breakdown of the Network Service revenue by customer.

b) Please confirm that no OATT customer uses point to point service. If this is not confirmed, please identify any revenue for such service (by customer) and identify where such revenue is included in this Schedule.

Response

a. Schedule 14-5 on page 154 did not appropriately show the correct breakdowns for 'Other Revenue' in 2016 and 2017, specifically for Network Service and Schedules 7 and 8.

There is one Network Service customer on PEI, and the correct Network Service revenue attributable to that customer is shown in the updated Schedule 14-5 below (updates are highlighted):

SCHEDULE 14-5						
Other Revenue($)						
	2016 Actual	2017 Actual	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
OATT						
Network Service	$ 5,166,393	$ 5,304,673	$ 6,222,300	$ 7,200,100	$ 7,258,500	$ 7,383,300
Schedule 1	303,898	315,831	287,300	286,400	288,200	291,800
Schedule 2	447,655	464,307	465,500	464,100	466,800	472,800
Schedule 3C	9,245	9,737	-	-	-	-
Schedule 4	833,834	155,313	-	-	-	-
Schedule 7	293,786	300,536	382,200	439,400	439,400	439,400
Schedule 8	992,104	1,085,114	1,303,800	1,466,200	1,465,900	1,466,200
Schedule 9	326,372	326,372	328,400	328,400	328,400	328,400
Schedule 10	17,555	-	-	-	-	-
Sub-total	8,390,843	7,961,884	8,989,500	10,184,600	10,247,200	10,381,900
Other						
Late Payment Charges	610,262	639,391	648,800	640,100	677,300	711,800
Connection Fees	479,177	463,552	471,600	477,900	505,800	530,700
Miscellaneous Revenue	673,772	859,462	1,026,300	858,400	894,600	827,200
Sub-total	1,763,211	1,962,405	2,146,700	1,976,400	2,077,700	2,069,700
Total Other Revenue	$ 10,154,054	$ 9,924,289	$ 11,136,200	$ 12,161,000	$ 12,324,900	$ 12,451,600

b. There are two Transmission Customers that use point-to-point service. The correct amounts for years 2016 and 2017 are shown in the response to IR-47 a).

IR-48 Please provide (preferably in Excel format, with all formulae intact) the derivation of the 2018 class revenues in Schedule 14-6, showing the unit prices and the monthly billing determinants to which they are applied.

Response

THIS RESPONSE WILL BE PROVIDED ON A CONFIDENTIAL BASIS UPON RECEIPT OF AN EXECUTED NON-DISCLOSURE AGREEMENT.

IR-49 Please provide (preferably in Excel format, with all formulae intact) the derivation of the 2019-2021 class revenues in Schedule 14-7, showing the unit prices and the monthly billing determinants to which they are applied.

Response

THIS RESPONSE WILL BE PROVIDED ON A CONFIDENTIAL BASIS UPON RECEIPT OF AN EXECUTED NON-DISCLOSURE AGREEMENT.

IR-50 With respect to Schedules 15-2 and 15-3:

a) Please provide (preferably in Excel format, with all formulae intact) the derivation of these Schedules.

b) Please provide similar schedules based on average monthly consumptions of 325 and 975 kWh.

Response

a. and b. The requested schedules are provided in Excel format in the following file:

- Multeese IRs #50.xlsx

IR-51 Regarding Schedule 15-2, please explain and provide the derivation of the Provincial Costs Recoverable, the Provincial Energy Efficiency Program, Cable Contingency Fund, RORA, and the Provincial Clean Energy Rebate.

Response

The Provincial Cost Recoverable is calculated by multiplying the annual consumption of 7,800 kWh by the approved rate of $0.00536 per kWh = $41.81 in each of 2016, 2017 and 2018.

The Provincial Energy Efficiency Program is calculated by multiplying the annual consumption of 7,800 kWh by the proposed collection rate set out in Schedule 4-3 of the Application as follows:

- 2019 = 7,800 kWh X $0.0007 per kWh = $5.46
- 2020 = 7,800 kWh X $0.0008 per kWh = $6.24
- 2021 = 7,800 kWh X $0.0009 per kWh = $7.02

The Cable Contingency Fund is calculated by multiplying the annual consumption of 7,800 kWh by the approved rate of $0.00027 per kWh = $2.11 in each of 2016, 2017, and 2018.

The RORA is calculated by multiplying the annual consumption of 7,800 kWh by the approved refund rates for 2016 thru 2018 per Order UE16-04 and by the proposed collection rate set out in Section 5.3.3 of the Application for 2019 thru 2021 as follows:

- 2016 = 7,800 kWh X $(0.00410) per kWh = $(31.96)
- 2017 = 7,800 kWh X $(0.00473) per kWh = $(36.91)
- 2018 = 7,800 kWh X $(0.00345) per kWh = $(26.87)
- 2019 = 7,800 kWh X $(0.00250) per kWh = $(19.53)
- 2020 = 7,800 kWh X $(0.00250) per kWh = $(19.53)
- 2021 = 7,800 kWh X $(0.00250) per kWh = $(19.53)

The Provincial Clean Energy Rebate is calculated by taking the total of all energy related charges up to the first 2,000 kWh of consumption, excluding the service charge, and multiplying by the rebate rate of 10%.

- 2018 = 1,443.59 – 323.04 = 1,120.55 X 10% = 112.55 X 8/12 mos = $74.70 (July 2018 to February 2019)
- 2019 = 1,430.83 – 323.04 = 1,135.98 X 10% = 113.60
- 2020 = 1,446.75 – 323.04 = 1,151.90 X 10% = 115.19
- 2021 = 1,443.59 – 323.04 = 1,168.21 X 10% = 116.82

IR-52 With respect to Schedule 15-4, please provide the derivation of the Provincial Costs Recoverable, the Provincial Energy Efficiency Program, Cable Contingency Fund, RORA. Also please explain why there is no Provincial Clean Energy Rebate.

Response

The Provincial Cost Recoverable is calculated by multiplying the annual consumption of 120,000 kWh by the approved rate of $0.00536 per kWh = $643.20 in each of 2016, 2017 and 2018.

The Provincial Energy Efficiency Program is calculated by multiplying the annual consumption of 120,000 kWh by the proposed collection rate set out in Schedule 4-3 of the Application as follows:

- 2019 = 120,000 kWh X $0.0007 per kWh = $84.00
- 2020 = 120,000 kWh X $0.0008 per kWh = $96.00
- 2021 = 120,000 kWh X $0.0009 per kWh = $108.00

The Cable Contingency Fund is calculated by multiplying the annual consumption of 120,000 kWh by the approved rate of $0.00027 per kWh = $32.40 in each of 2016, 2017 and 2018.

The RORA is calculated by multiplying the annual consumption of 120,000 kWh by the approved refund rates for 2016 thru 2018 per Order UE16-04 and by the proposed collection rate set out in Section 5.3.3 of the Application for 2019 thru 2021 as follows:

- 2016 = 120,000 kWh X $(0.00410) per kWh = $(491.68)
- 2017 = 120,000 kWh X $(0.00473) per kWh = $(567.81)
- 2018 = 120,000 kWh X $(0.00345) per kWh = $(413.42)
- 2019 = 120,000 kWh X $(0.00250) per kWh = $(300.47)
- 2020 = 120,000 kWh X $(0.00250) per kWh = $(300.47)
- 2021 = 120,000 kWh X $(0.00250) per kWh = $(300.47)

The Provincial Clean Energy Rebate is only available to residential customers and does not apply to general service.

IR-53 Please provide Schedule 15-4 for a 50KW customer whose load factor is 15% and 50%.

Response

The following is Schedule 13-4 for a 50 KW customer with a 15% load factor:

SCHEDULE 15-4 Annual Cost for General Service Customer (5,475kWh/50KW per Month/65,700 kWh/600KW per Year)						
	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Service Charge	$ 294.84	$ 294.84	$ 294.84	$ 294.84	$ 294.84	$ 294.84
Demand Charge	4,834.80	4,834.80	4,834.80	4,834.80	4,834.80	4,834.80
Basic Energy Charge	10,368.78	10,801.86	11,075.82	11,304.93	11,598.03	11,770.29
ECAM Charge	135.24	78.03	37.78	239.37	117.23	96.94
Provincial Costs Recoverable	352.15	352.15	352.15	-	-	-
Provincial Energy Efficiency Program	-	-	-	45.99	52.56	59.13
Cable Contingency Fund	17.74	17.74	17.74	-	-	-
RORA	(269.19)	(310.88)	(226.35)	(164.50)	(164.50)	(164.50)
Sub-total	15,734.36	16,068.55	16,386.78	16,555.43	16,732.95	16,891.49
HST*	2,268.37	2,410.29	2,458.02	2,483.31	2,509.94	2,533.72
Total Annual Cost	**$ 18,002.72**	**$ 18,478.84**	**$ 18,844.80**	**$ 19,038.74**	**$ 19,242.90**	**$ 19,425.21**
Percentage Annual Increase (%)	**2.8%**	**2.6%**	**2.0%**	**1.0%**	**1.1%**	**0.9%**

* HST Rate increased from 14% to 15% effective October 1, 2016
50 KW @ 15% load factor = 50 KW X 24 hours X 365 days X 15% = 65,700 kWh consumption per year.

The following is Schedule 13-4 for a 50 KW customer with a 50% load factor:

SCHEDULE 15-4 Annual Cost for General Service Customer (18,250kWh/50KW per Month/219,000 kWh/600KW per Year)						
	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Service Charge	$ 294.84	$ 294.84	$ 294.84	$ 294.84	$ 294.84	$ 294.84
Demand Charge	4,834.80	4,834.80	4,834.80	4,834.80	4,834.80	4,834.80
Basic Energy Charge	26,526.60	27,634.20	28,337.40	28,919.10	29,672.10	30,120.30
ECAM Charge	450.79	260.11	125.93	797.90	390.76	323.13
Provincial Costs Recoverable	1,173.84	1,173.84	1,173.84	-	-	-
Provincial Energy Efficiency Program	-	-	-	153.30	175.20	197.10
Cable Contingency Fund	59.13	59.13	59.13	-	-	-
RORA	(897.31)	(1,036.26)	(754.49)	(548.35)	(548.35)	(548.35)
Sub-total	32,442.69	33,220.67	34,071.45	34,451.59	34,819.35	35,221.81
HST*	4,677.15	4,983.11	5,110.72	5,167.74	5,222.90	5,283.27
Total Annual Cost	**$ 37,119.85**	**$ 38,203.78**	**$ 39,182.16**	**$ 39,619.33**	**$ 40,042.25**	**$ 40,505.09**
Percentage Annual Increase (%)	**6.1%**	**2.9%**	**2.6%**	**1.1%**	**1.1%**	**1.2%**

* HST Rate increased from 14% to 15% effective October 1, 2016
50 KW @ 50% load factor = 50 KW X 24 hours X 365 days X 50% = 219,000 kWh consumption per year

IR-54 Please provide Appendix 4 as an Excel file, with all formulae intact and functioning.

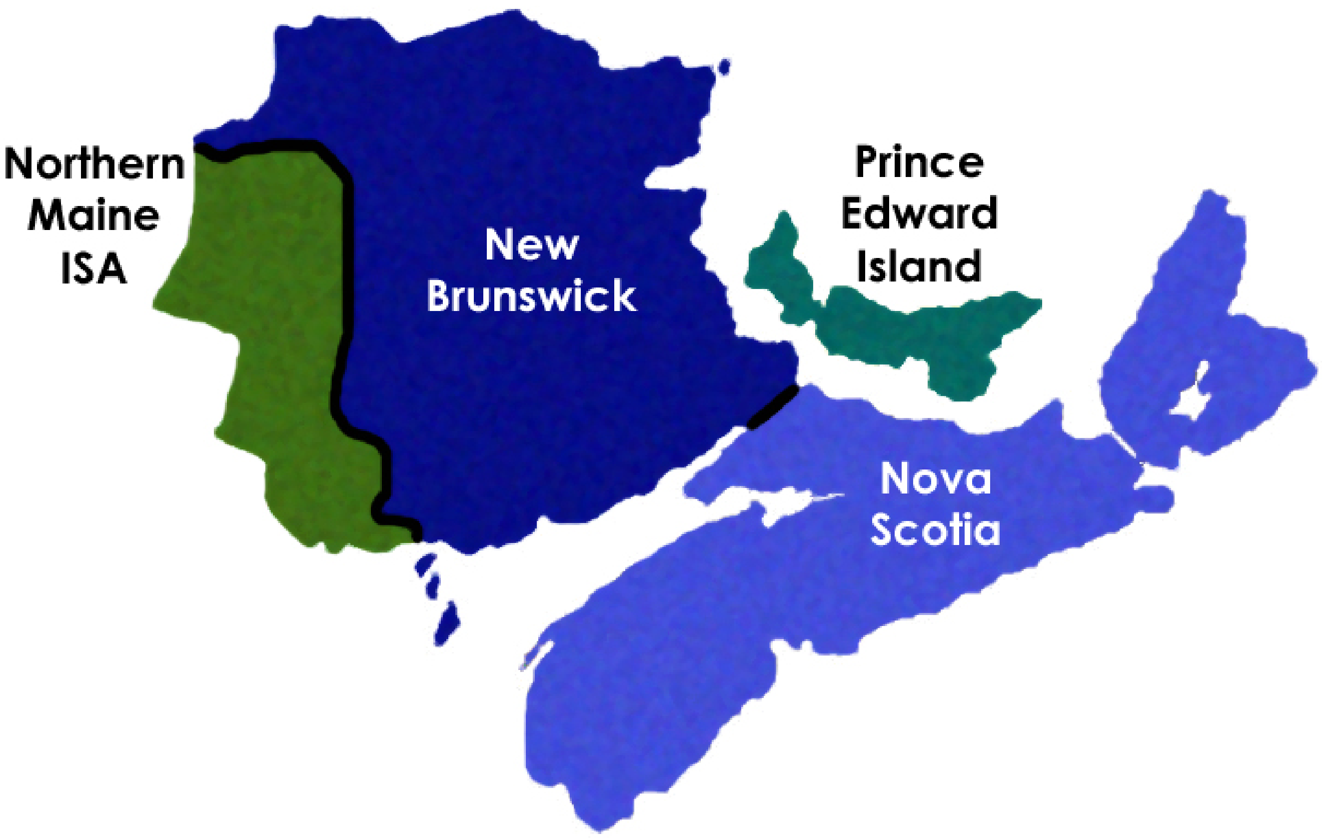
Response

As requested Appendix 4 is provided in Excel format in the following file:

- Multeese IRs #54.xlsx

NPCC
2018 MARITIMES AREA
INTERIM REVIEW OF RESOURCE ADEQUACY

Approved by RCC December 4, 2018



NEW BRUNSWICK POWER CORP.
NOVA SCOTIA POWER INC.
MARITIME ELECTRIC COMPANY, LIMITED
NORTHERN MAINE ISA, INC.

December 4, 2018

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EXECUTIVE SUMMARY

The 2018 Maritimes Area Interim Review of Resource Adequacy (2018 Interim Review), covering the period of January 2019 through December 2021, has been prepared to satisfy the Reliability Assessment Program as established by the Northeast Power Coordinating Council (NPCC). This 2018 Interim Review follows the resource adequacy review guidelines as specified in the *NPCC Regional Reliability Reference Directory #1 Appendix D (Adopted: September 30, 2015).*

The Maritimes Area will comply with the NPCC resource adequacy criterion that requires a loss of load expectation (LOLE) value of not more than 0.1 days/year for all years of this 2018 Interim Review. Major assumptions are shown in Table 1 below. LOLE values for each year of the 2018 Interim Review and the 2016 Maritimes Area Comprehensive Review of Resource Adequacy (2016 Comprehensive Review) are shown in Table 2 below.

Table 1 - Summary of Major Assumptions

MAJOR ASSUMPTIONS	
Load Forecast	2018 forecast for all jurisdictions
Load Shape	2011/12 (all years)
Resource Adequacy Criterion	Loss of Load Expectation not more than 0.1 days/year
Maritimes Required Reserve	20% of peak firm load
Interconnection Benefits	300 MW
Area Purchases/Sales	2019 - sale of 114 MW 2020 - sale of 110 MW and purchase of 153 MW 2021 - sale of 69 MW
Maritime Link Project	2020 - 153 MW firm Nova Scotia (NS) purchase from Newfoundland - 153 MW coal-fired generator retired in NS
Wind	2019 - 57 MW added in New Brunswick (NB) 2021 - 40 MW added in NB
Unit Removals	2019 - 5 MW diesel fired generation retired in NB - mothballing of 70 MW of biomass fuelled generation in Northern Maine (NM) - 7 MW of oil fired generation retired in Prince Edward Island (PEI) - 38 MW of oil fired generation in PEI laid up during summers from 2019 onward 2020 - 10 MW of oil fired generation retired in PEI

Unit Additions	2021 - 18 MW diesel generator in PEI

Table 2 - Maritimes Area LOLE Values from 2019 to 2021

Year	2018 Interim Review (days/year)	2016 Comprehensive Review (days/year)
2019	0.002	0.003
2020	0.002	0.003
2021	0.002	0.004

Area load and capacity projections from 2019 to 2021 for this 2018 Interim Review are little changed from those projected for the 2016 Comprehensive Review and still practically flat.

LOLE results for the 2018 Interim Review were slightly lower from 2019 to 2021 than the 2016 Comprehensive Review results due to a slight increase in forecast reserve margins in NS.

There are no changes in this 2018 Interim Review with respect to fuel supplies, emergency operating procedures, or market rules.

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1.0 INTRODUCTION

This 2018 Interim Review is the second update of the 2016 Comprehensive Review approved by the Reliability Coordinating Committee (RCC) on December 6, 2016. The Maritimes Area is a winter peaking area with separate jurisdictions in NB, NS, PEI, and NM. New Brunswick Power Corporation (NB Power) is the Reliability Coordinator for the Maritimes Area, with its system operator functions performed by its Transmission and System Operator division under a regulator approved Standards of Conduct.

2.0 ASSUMPTION CHANGES

No changes were made in this 2018 Interim Review with respect to fuel supplies, emergency operating procedures, or market rules.

Upgrades to the transmission interface between PEI and NB have increased the transfer capability from 222 MW (2016 value) to the current value of 240 MW in 2018. Completion of the re-termination of a circuit on PEI (scheduled for Q4 2018) will further increase the capacity of the interface to 300 MW in both directions by 2019. After completion of these upgrades, transfer capability to PEI will exceed their peak load.

With the completion of the installation of a larger transformer at the Tinker substation feeding NM and the 2019 transfer of 20 MW of load from that system to a direct NB feed, the transfer capability into NM will exceed its peak load beginning in 2019.

NB installed wind capacity is expected to increase by 57 MW by 2019 and a further 40 MW by 2021.

2.1 Demand Forecast

The Maritimes Area coincident peak demand is forecast to occur during the month of January each year. Table 3 shows a comparison of the annual peak demands used in this 2018 Interim Review versus the 2016 Comprehensive Review.

Table 3 - Maritimes Area Peak Demand Forecast from 2019 to 2021

Winter Peak (January)	2018 Interim Review (MW)	2016 Comprehensive Review (MW)	Difference (MW)
2019	5,391	5,416	-25
2020	5,407	5,432	-25
2021	5,400	5,426	-26
2019 to 2021 Average Compound Annual Growth Rate			
Growth Rate	0.08%	0.09%	

Forecast peak demand in the Maritimes Area is effectively flat over the period of this 2018 Interim Review and practically unchanged from the 2016 Comprehensive Review.

2.2 Resources and Sales

Resource and external sales changes for this 2018 Interim Review versus the 2016 Comprehensive Review include the following:

- Retirement of 17 MW of oil fired PEI capacity before 2021 with a further 38 MW of oil fuelled capacity on PEI will be laid up for summer periods starting in 2019 related to the increase in transfer capability from NB to PEI,
- Installation of an 18 MW diesel generator on PEI in January 2021,
- Mothballing of two biomass fuelled units totaling 70 MW of capacity in Maine by 2019 related to the transfer of about 20 MW of Houlton Water load from Northern Maine to the New Brunswick sub-area and the installation of a higher capacity transformer feeding northern Maine,
- Additional new NB installed wind capacity, 57 MW by 2019 and 40 MW by 2021,
- Removal of a 5 MW diesel generator in NB,
- Short term firm external sales to New England of 114 MW, 110 MW and 69 MW during 2019, 2020, 2021 respectively (sales are netted against resources).

Table 4 shows the year by year January resources forecast for this 2018 Interim Review compared to the 2016 Comprehensive Review.

Table 4 - Maritimes Area Resources Forecast for 2019 to 2021

Year	2018 Interim Review (MW, with on-peak wind)			2016 Comprehensive Review (MW, with on-peak wind)			Difference (MW)
	Conventional	Wind	Total	Conventional	Wind	Total	Total
2019	6,716	521	7,237	6,803	496	7,299	-62
2020	6,743	521	7,264	6,958	496	7,454	-190
2021	6,774	537	7,311	6,958	496	7,454	-143

Conventional resources in Table 4 are from the peak load month of January of each year and include installed generation, contracted external purchases (added) and contracted sales (subtracted), and tie benefits of 300 MW (see Section 3.5 below). Wind capacity used in Table 4 is the total amount of wind generation modeled during the hour of the Maritimes Area coincident peak load based on the load shape used for the LOLE calculations. Because of the variability of wind from hour to hour, this does not represent the effective load carrying capability or capacity value of the wind resources. Forecast hourly wind generation capacity is subtracted from hourly loads for LOLE analysis.

2.3 Comparison of Forecast and Required Reserve

The Maritimes Area uses a 20% reserve criterion for planning purposes. This criterion is not mandated but has historically resulted in levels of reserve that are closely correlated to the reserve levels necessary to meet the NPCC resource adequacy criterion. A close correlation between this 20% reserve criterion and NPCC's LOLE criterion of not more than 0.1 days per year of load losses due to resource deficiencies was established in the 2016 Comprehensive Review. Table 5 shows annual values for the forecast, minimum and required reserves at 20%. In each year of this 2018 Interim Review, the forecast reserve exceeds the 20% required reserve criterion.

Table 5 - Forecast, Minimum, and Required Reserve - January 2019 to 2021

Year	Forecast Capacity (MW)	Peak Load (MW)	Inter. Load (MW)	Forecast Reserve		Minimum Reserve		Required Reserve	
				MW	%	MW	%	MW	%
2019	7,237	5,391	267	2,113	41	1,974	41	1,025	20
2020	7,264	5,407	265	2,121	41	1,917	40	1,029	20
2021	7,311	5,400	264	2,175	42	2,043	41	1,027	20

$$\text{Forecast Reserve (\%)} = \frac{[\text{Forecast Capacity} - (\text{Peak Load} - \text{Inter. Load})]}{(\text{Peak Load} - \text{Inter. Load})} * 100\%$$

$$\text{Minimum Reserve (\%)} = \frac{\text{Min. of Hourly } [\text{Capacity} - (\text{Load} - \text{Inter. Load})]}{(\text{Load} - \text{Inter. Load})} * 100\%$$

Forecast wind generation outputs during the Maritimes Area peak load hour are used for the forecast capacity totals in Table 5. Hour by hour reserve values are used for the minimum reserve calculations.

2.4 Interconnection Tie Benefits

In this 2018 Interim Review, 300 MW of interconnection tie benefits from New England are assumed. These tie benefits are based on a 2011 decision by the New Brunswick Market Advisory Committee to recognize the lowest historical Firm Transmission Capacity posted from summer peaking New England to winter peaking New Brunswick since the commissioning of the second 345 kV tie between these systems in December 2007. This is unchanged from the 2016 Comprehensive Review. In the CP-8 report *Review of Interconnection Assistance Reliability Benefits (December 31, 2015, Approved by RCC March 2, 2016)* the “As Is” estimated tie benefit potential for the Maritimes Area is 702 MW and 1012 MW for the years 2016 and 2020 with an export of 200 MW modeled in both test years. Based on this study, the 300 MW of tie benefits assumed for this 2018 Interim Review is conservative.

2.5 Support from External Interconnections

For the purposes of this 2018 Interim Review, interconnection support from neighbouring NPCC Areas was limited to 300 MW of tie benefits for all years. In addition, beginning in mid-2020, 153 MW of firm contracted capacity is expected to be available from a new 500 MW Maritimes Area HVDC link between NS and Newfoundland and Labrador completed in late 2017. This added external support will offset the simultaneous retirement of the same amount of coal fueled capacity in Nova Scotia. Non-firm capacity from Newfoundland and Labrador was not modeled.

3.0 FUEL SUPPLIES

The 2016 Comprehensive Review showed that the Maritimes Area has a diversified mix of resources such that there is not a high degree of reliance upon any one type or source of fuel. This diversified resource mix is unchanged for this 2018 Interim Review.

Generation fueled solely by natural gas accounts for just 7% of Maritimes Area capacity resources with supply options that include local shale gas fields, eastern off-shore production, western pipelines, and a liquefied natural gas receiving and re-gasification terminal. These supply options help to significantly reduce the exposure of the Maritimes Area to natural gas fuel disruptions.

4.0 LOLE RESULTS

Area load and capacity projections from 2019 to 2021 for this 2018 Interim Review are little changed from those predicted for the 2016 Comprehensive Review resulting in LOLE values that are practically the same.

A summary of the Maritimes Area LOLE values from 2019 to 2021 is shown in Table 6 below. All LOLE values for this 2018 Interim Review meet the NPCC resource adequacy criterion.

Table 6 - Maritimes Area LOLE Values from 2019 to 2021

Year	2018 Interim Review (days/year)	2016 Comprehensive Review (days/year)
2019	0.002	0.003
2020	0.002	0.003
2021	0.002	0.004

In the 2016 Comprehensive Review, the Maritimes Area examined a high growth scenario based on adding a fixed value of 1% compounding growth to the average annual growth rate examined during the period.

As a check on this scenario for this 2018 Interim Review, a compounding load growth rate of 1.085% per year was added uniformly across all sub-areas during the two future years of the forecast period from 2020 thru 2021 using 2019 as the base year. The LOLE values obtained for the future years of 2020 thru 2021 are shown in Table 7 and still meet the NPCC resource adequacy criterion.

Table 7 - Maritimes Area LOLE for High Load Growth Scenario

Year	2018 Interim Review (days/year)	2016 Comprehensive Review (days/year)
2019	0.002	0.006
2020	0.003	0.010
2021	0.005	0.019

5.0 CONCLUSION

Results of this 2018 Interim Review show the Maritimes Area will comply with the NPCC resource adequacy criterion requiring a LOLE value of not more than 0.1 days/year for all years from 2019 to 2021.

Turbine-Generator 10

Report Title	Author and/or Company	Unit	Report No.	Date of Report	Scope of Report
Unit 10 1989 Minor Overhaul (& Life Extension Recomm	GEC ALSTHOM LIMITED	**Turbine 10**	TS 1404	Wednesday, April 4, 1990	This report covers the work carried out during the minor overhaul of Unit No. 10 in 1989. This included the following work: removal of all steam side components from governor valve assemblies and rebuild with new; opening and inspecting of C.I.E.S. valves; the checking of L.P./Generator coupling alignment. The outage commenced on the 16th of October, 1989 and the machine was returned to service on the 4th of November, 1989.
20 MW Generator	GEC ALSTHOM LIMITED	**Turbine 10**	CD 0041	May-91	This report covers the life extension inspections and tests on Unit No. 10 Generator during a visiting period of April - May 1991. The work required the removal of the generator rotor from the stator, and during inspections, partially stripped. This also allowed for a complete inspection of the stator.
Eddy Current Inspection: H.P. Feedwater Heater	Global Testing Technologies	**Turbine 10**	G.F. 91-8024	May-91	This report documents the eddy current inspection of the H.P. Feedwater Heater Unit No. 10, Maritime Electric Company Limited, Charlottetown, P.E.I. was carried out in May 1991. A total of 388 tubes were inspected on the unit.
Eddy Current Inspection: L.P. Feedwater Heaters	Global Testing Technologies	**Turbine 10**	G.F. 91-8025	May-91	This report documents the eddy current inspection of the L.P. Feedwater Heaters, Unit No. 10 carried out in May 1991. A total of 284 (142 U-bend) tubes are contained in each unit.
Unit 10 Turbine Generator Overhaul	Bretech Inspection (N.D.T.) Ltd.	**Turbine 10**	91091	Monday, May 6, 1991	This is an inspection report performed on No. 10 Turbine and Components from April 21, 1991 to May 4, 1991. The inspection included various non destructive testing techniques on the #10 Turbine machine and associated components. The inspections conducted are listed in chronological sequence throughout the report.
Unit 10 Life Extension Survey	GEC ALSTHOM LIMITED	**Turbine 10**	TS 1478	Friday, October 11, 1991	This report covers details of the survey work performed, the remedial work carried out and photographs of defective components and clearance records. The survey is dated for the 24th day of July, 1991.
Unit 10 1992 Overhaul	GEC ALSTHOM LIMITED	**Turbine 10**	TS 1606	Tuesday, March 9, 1993	This reports covers the major overhaul on the turbine, which commenced on August 3rd, 1992, to carry out recommendations made after the 1991 life extension survey. The work included replacing all gland segments, reblading of the inlet nozzle boxes, refurbishing of C.I.E.S. valves and the governor, and fitment of new steam chest fasteners. No generator work was undertaken. The unit was returned to electrical turning gear on November 19th, 1992 and steamed on December 8th 1992.
Unit 10 2004 Outage: Turbine End Report	ALSTOM	**Turbine 10**	TS 2378	Friday, February 18, 2005	The report covers the major overhaul which commenced on September 3rd, 2004. The principal outage activities included: inspection and overhaul of the turbine; inspection and overhaul of the main steam admission valves; inspection and overhaul of all main bearings and associated pedestals; and inspection and overhaul of the generator, exciter and permanent magnet generator. The unit was initially run up after the overhaul on November 4th but due to problems encountered with the governing valves the unit was not successfully returned to service until November 25th, 2004.
Unit 10 Generator Re-Wedge 2005	Siemens	**Turbine 10**	90581	May 2005	The report covers the re-wedge of the Generator Stator on both Unit #10 and #9. Testing of the rotors and stators was completed to verify operational integrity. An El-Cid test was completed both before and after wedge replacement. PI, Megger and Doble tests were completed on the stator to verify integrity.

Turbine 10 **Boiler 10**

Report Title	Author and/or Company	Unit	Report No.	Date of Report	Scope of Report
Unit 10 Condition Assessment Report, Phase I: Preplanning	Foster Wheeler Ltd.	**Boiler 10**	7-22-3157	Wednesday, January 30, 1991	This preplanning report of the Babcock & Wilcox two drum Stirling Boiler is based on two criteria: Firstly, an estimation of the boiler's potential critical areas are based on records of repairs, water treatment and operating data and a review of the metalurigical reports from Boiler 9. Boiler 9 is similar to Boiler 10 in exception to burner modifications and the addition of an I.D. fan on Boiler 10.
Unit 10 Condition Assessment Report, Phase III: Engineering Evaluation, Analysis, and Recommendations	Foster Wheeler Ltd.	**Boiler 10**	7-22-3157	Tuesday, November 12, 1991	This report covers the extensive Condition Assessment program of three phases, carried out on Boiler #10. To access its condition, inspections performed were: visual inspection, ultrasonic thickness inspection, magnetic particle inspection, ultrasonic flaw detection, boroscopic inspection, tube sample analysis, replication and tube pit measurement. Phase 1, consisted of Pre-Outage Planning and review of MECL operating records. Phase 2, consisted of On-site work which was performed from March 19th, 1991 until May 28th, 1991. Phase 3 consisted of the Engineering Evaulation, Analysis and Recommending based on findings.
Mud Drum Tube Inspection	Bretech Inspection (N.D.T.) Ltd.	**Boiler 10**	95049C	Friday, May 5, 1995	This is an inspection report performed on Boiler No. 10 from April 3 to 7, 1995. During this inspection, the following were performed: ultrasonic thickness testing, near drum inspection, initial tube cleaning, Internal Rotary Inspection was performed on 10% of the generating bank tubes.
Visual & NDT Report for Boilers 4, 5, 6, 9, and 10	Alstom	**Boilers 4, 5, 6, 9, & 10**	C-0120025	Friday, November 23, 2001	This report details the inspection performed by Alstom in 2001 of the Generating Bank Tubes in Boilers 4, 5, 6, 9, & 10.

Turbine-Generator 9

Report Title	Author and/or Company	Unit	Report No.	Date of Report	Scope of Report
Turbine Generator & Auxiliaries, NDT Report	WARNOCK HERSEY	**Turbine 9**	G.F. 90-8029-31	Jun-90	This is the Non-Destructive Examination report of No. 9 Turbine and related components as well as the Eddy Current results of Global Testing Technologies on the Feedwater Heaters and Turbine Lube Oil Cooler.
Life Extension Survey and Overhaul	GEC ALSTHOM LIMITED	**Turbine 9**	TS 1446	Aug-90	This report details the survey work carried out and includes references to the extensive N.D.E. of all critical components including bore inspections of the turbine and generator rotors. The work began May 7, 1990 after being shutdown on March 30, 1990.
Life Assessment of Turbine and Generator Rotors	GEC ALSTHOM LIMITED	**Turbine 9**	31463	Nov-90	This report includes the assessments of the turbine rotor, and generator rotor. Appendents include an Extract from GEC ALSTHOM Report TS 1446 "Life Extension - Survey and Overhaul", Aug 1990; Report from Dynacon Systems Inc. "Non-Destructive Examination of Unit 9 HP-LP Turbine Rotor", June 1990; and Report from Dynacon Systems Inc. "Non-Destructive Examination and Condition Assessment of Unit 9 Generator Rotor and Retaining Rings", June 1990.
Minor Overhaul 1991	GEC ALSTHOM LIMITED	**Turbine 9**	TS 1510	Thursday, November 28, 1991	This report details the replacement of the turbine governor valves and No. 2 and 3 bearing shells during the 1991 boiler outage. The replacement governor valves (not GEC ALSTHOM manufacture) had different seat profiles to the original design, thus being incompatible with the cam and governor design. A balance exercise by a GEC ALSTHOM balance engineer reduced the No. 2 bearing vibration.
1993 Overhaul	GEC ALSTHOM LIMITED	**Turbine 9**	TS 1644	Tuesday, October 19, 1993	This report details the overhaul work content based on recommendations made in the 1990 Life Extension survey. The work included the replacement of all turbine gland segments, refurbishment of combined stop & emergency valves, the overhaul of governor and associated gears and replacement of bearing liners where necessary. A turbine rotor low speed balance was required to correct reported turbine vibration. The generator rotor end bells were replaced and the stator rewedged. The overhaul began in early April 1993 and was steamed on August 5th 1993.
Last Row Blade Inspections	ALSTOM	**Turbines 6, 7, 8, 8, & 10**	TS 2188	Friday, November 30, 2001	The report outlines the visit which was made to site to conduct inspections on the last row blades of several machines, with a view to determining anticipated blade life. The inspections were carried out in situ and did not include NDE. No major problem areas were identified.
Turbine Generator #9 Inspection	Canspec Group Inc.	**Turbine 9**		Monday, November 4, 2002	This report contains details of the inspection performed by Canspec personnel during the period of September 19 through September 29, 2002. Non-Destructive Testing was performed on various parts of Turbine Generator #9. Inspections methods include: Ultrasonic; Magnetic Particle; and Liquid Penetrant.
Unit 9 2002 Outage	ALSTOM	**Turbine 9**	TS 2250	Thursday, January 2, 2003	This report details the major overhaul which commenced on September 3rd, 2002. The principal outage activities were: inspection and overhaul of the turbine; inspection and overhaul of the main steam admission valves; inspection and overhaul of the front pedestal control equipment; inspection and overhaul of all main bearings and associated pedestals; and inspection and overhaul of the generator, exciter and permanent magnet generator. The unit was successfully returned to service on October 19th, 2002.
Unit 9 Generator Re-Wedge 2005	Siemens	**Turbine 9**	90581	May 2005	The report covers the re-wedge of the Generator Stator on both Unit #10 and #9. Testing of the rotors and stators was completed to verify operational integrity. An El-Cid test was completed both before and after wedge replacement. PI, Megger and Doble tests were completed on the stator to verify integrity.

Boiler 9

Report Title	Author and/or Company	Unit	Report No.	Date of Report	Scope of Report
Material Condition Assessment of Boiler '	Babcock & Wilcox	**Boiler 9**	ƆD: 91:7096-01-01:(	Jun-90	This report details the examination of seven boiler tubes from Unit 9. The tubes were examined by Metallurgy Department of the Babcock & Wilcox Alliance (Ohio) Research Center) The objectives were (1) to access the in-service condition of all seven tubes, (2) to examine two attachment welds, and (3) to examine twenty field surface replicas taken of the attemperator header, primary superheater header and a main steam pipe weld. The results from examination of the replicas are entirely contained in the appendix.
Boiler NDT Inspection Report	WARNOCK HERSEY	**Boiler 9**	-	Monday, June 25, 1990	This report contains a detailed account of our inspection program in relation to location, extent and result of inspections carried out. The Non-Destructive examination program on Boiler No. 9 and related components occurred during the period of May 23 to June 15, 1990.
Rebuilding of Boiler following explosion in 1994	-	**Boiler 9**	-	1995	** There are records and reports on this project, but not one report completely covers this project.
Visual & NDT Report for Boilers 4, 5, 6, 9, and 10	Alstom	**Boilers 4, 5, 6, 9, & 10**	C-0120025	Friday, November 23, 2001	This report details the inspection performed by Alstom in 2001 of the Generating Bank Tubes in Boilers 4, 5, 6, 9, & 10.

Turbine-Generator 8

Report Title	Author and/or Company	Unit	Report No.	Date of Report	Scope of Report
Eddy Current Inspection Reports: Unit No.8 H.P Heater	Global Testing Technologies	**Turbine 8**	G 92022 F	October 1991	This report documents the eddy current inspection of the H.P. Feedwater Heater for Unit No. 8, Maritime Electric Company Limited, Charlottetown, P.E.I. Inspection was carried out in October 1991.
Generator No. 8 Core Tests	Ontario Hydro / Westinghouse	**Turbine 8**	RPTMECO2	Monday, November 18, 1991	A low flux EL-CID core test, a Heavy Current Stator Core Ring Flux Test, and thermographic camera survey was carried out by a specialist team from Ontario Hydro on September 16, 1991 as part of Maritime Electric's Plant Life Extension Program.
Rotor Repairs and Stator Inspection Unit No.8	NEI Parsons Canada Limited	**Turbine 8**	92-348E	December 1991	This report covers work for rotor repairs and stator inspection. The rotor repairs included: remove balance rings and end caps; remove end winding packings & inspect; remove brass wedges for alpha/beta testing; inspect end windings; leakage pads; new end winding insulation, reinstall equipment. On stator: conduct stator slot wedge survey; end winding inspection; cleaning of end winding; El-Cid tests & Core Flux Test
Life Extension Survey of Turbine Generator	NEI Parsons Canada Limited	**Turbine 8**	92-352M	Friday, May 15, 1992	This report outlines the life extension survey conducted on Unit No. 8. Scope of inspection work included: the turbine, the generator, and any auxiliaries of the unit. Appendents include: Hodgson Inspection Services NDT Test; Magnetic Particle and Boresonic Inspection of Turbine Rotor Forging; Hodgson Inspection Services NDT on Bearings; and Vibration Performance Test. Inspection duration: September 9 - December 1991.
Planned Outage Report	Parsons Turbine Generators Canada Ltd.	**Turbine 8**	94-414M	Friday, November 4, 1994	This report outlines the activities performed during the outage which was planned for machine life extension. The main objective was to carry out the work recommended after the last inspection in 1991. This outage was from August 2 to October 30, 1994.
1995 Outage	Parsons Turbine Generators Canada Ltd.	**Turbine 8 & 6**	96-441M	Nov-95	This report outlines the activities performed during the 1995 Outage of Turbine 6 and Turbine 8. On Unit 6, the objective was to remove the upper cylinder and inspect the half joint flange in aiming to fix the steam leak on the turbine cylinder. On Unit 8, the main objective was to remove the generator rotor and ship it to St. Catherines to have the end caps replaced. Other activity included: lube oil flush; bearing inspection; replacement of the main EST cover brushes and steam strainer; and replacement of the governor regulating bush and plunger.
Last Row Blade Inspections	ALSTOM	**Turbines 6, 7, 8, 8, & 10**	TS 2188	Friday, November 30, 2001	The report outlines the visit which was made to site to conduct inspections on the last row blades of several machines, with a view to determining anticipated blade life. The inspections were carried out in situ and did not include NDE. No major problem areas were identified.
Unit 8 Overhaul Report	Siemens	**Turbine 8**		2006	This report outlines the activities performed during an outage to inspect and perform minor refurbishment of the Electrical and Mechanical ends of #8 Steam Turbo-Generator.
CO2 Cleaning of Electrical Stator, El-Cid Testing; Test, Clean & Repair Armature & Stator at Siemens-Moncton	Siemens	**Turbine 8**	41095849	April 2006	This report outlines the activities performed by Siemens to CO2 clean the stator on Unit #8, perform El-Cid testing (Dat Van Tran) and test, clean & repair armature & stator at Siemens-Moncton,NB facility.

Turbine-Generator 7

Report Title	Author and/or Company	Unit	Report No.	Date of Report	Scope of Report
Eddy Current Inspection Reports: Unit No.7 H.P Heater; LP Heater #1; LP Heater #2; and Drain Condenser	Tri-Scan Technology inc.	**Turbine 7**	T.T. 4-216 T.T. 4-216 T.T. 4-218 T.T. 4-219	Monday, May 2, 1994 Monday, May 2, 1994 Monday, May 2, 1994 Monday, May 2, 1994	These 4 reports document the eddy current inspection of the H.P. Feedwater Heater; LP Feedwater Heaters # 1 & #2; and the Drain Condensor for Unit No. 7, Maritime Electric Company Limited, Charlottetown, P.E.I. Inspection was carried out in May 1994.
Life Extension Program Work Report & Bretech Inspection Report		**Turbine 7**	70 94062	Wednesday, August 24, 1994 Tuesday, May 31, 1994	This report includes a field service report by Brown Boveri as well as an inspection report by Bretech. The FSR has the following work noted: turbine rotor stator blading and oil control system (in good condition), the steam parts for steam control valves, cages and spindels #1 to 4 were in very bad condition (replaced), steam seat and spindel on the main stop valve was replaced, new speed governor was installed, horizontal turbine casing splitline (in good condition), thrust bearing #1 and journal bearing #2, 3 and 4 (good condition), repair work
Last Row Blade Inspections	ALSTOM	**Turbines 6, 7, 8, 8, & 10**	TS 2188	Friday, November 30, 2001	The report outlines the visit which was made to site to conduct inspections on the last row blades of several machines, with a view to determining anticipated blade life. The inspections were carried out in situ and did not include NDE. No major problem areas were identified.

Boiler 6

Report Title	Author and/or Company	Unit	Report No.	Date of Report	Scope of Report
Boiler # 6 Condition Assessment Report	Foster Wheeler Ltd.	**Boiler 6**	6460-9583	Wednesday, April 6, 1994	A condition assessment inspection was performed on Boiler # 6 at the Cumberland Street Plant. The inspection was performed by Foster Wheeler Ltd. from February 21, 1994 until March 2, 1994. The inspections performed to assess the condition of Boiler #6 included: visual inspection, ultrasonic thickness inspection, magnetic particle inspection, and borescope inspection. It was Foster Wheeler's recommendation following the inspection that Boiler #6 be completely re-tubed to significantly increase the boiler's operating reliability for an additional 15 year operating period.
Retubing of Boiler 6 (except steam drums + mud drums)	-	**Boiler 6**	-	1994	** There are records and reports on this project, but not one report completely covers this project.
Visual & NDT Report for Boilers 4, 5, 6, 9, and 10	Alstom	**Boilers 4, 5, 6, 9, & 10**	C-0120025	Friday, November 23, 2001	This report details the inspection performed by Alstom in 2001 of the Generating Bank Tubes in Boilers 4, 5, 6, 9, & 10.

Boiler 5

Report Title	Author and/or Company	Unit	Report No.	Date of Report	Scope of Report
Unit 5 Condition Assessment Report, Phase I: Preplanning	Foster Wheeler Ltd.	**Boiler 5**	6460-8614	Wednesday, February 13, 1991	This preplanning report of the Foster Wheeler two drum Steam Generator is based on two criteria: Firstly, an estimation of the boiler's potential critical areas are based on records of repairs, water treatment and operating data and a superficial visual inspection. It is most important to note that the intention of this report is to anticipate potential critical areas of the boiler for an elaborate investigation to be conducted at a later date. Secondly, an investigation to include visual inspections, UT thickness measurements, replication, magnetic particle inspection, ultrasonic flaw detection, boroscope inspection of tubes and headers and tube sample removal for lab analysis. Inspection period: August 15 - November 6, 1995
Superheater and Partial Frontwall Tubes	Foster Wheeler Ltd.	**Boiler 5**	-	01-Nov-93	This record shows that the superheater and partial frontwall tubes were replaced on Boiler #4 in late 1993.
Visual & NDT Report for Boilers 4, 5, 6, 9, and 10	Alstom	**Boilers 4, 5, 6, 9, & 10**	C-0120025	Friday, November 23, 2001	This report details the inspection performed by Alstom in 2001 of the Generating Bank Tubes in Boilers 4, 5, 6, 9, & 10.

Boiler 4

Report Title	Author and/or Company	Unit	Report No.	Date of Report	Scope of Report
Unit #4 Boiler Audit	MBB - Trecan Incorporated	**Boiler 4**	185-5259	Friday, July 31, 1992	This report details the inspection services performed on the Boiler No. 4 in an Audit. The intent of the audit was to examine the current condition and operation of the boiler with recommendations for future maintenance and (major repairs/refurbishment) to allow for an additional 15 years of operation.
Bridgewall and Superheater Tube Replacement	Foster Wheeler Ltd.	**Boiler 4**	-	01-Nov-93	This record shows that the bridgewall and superheater tubes were replaced on Boiler #4 in late 1993.
Technical Services Report: Superheater Tube Analysis	ALSTOM	**Boiler 4**	MSE-04-R-05	-	This report outlines the examination of superheater tubes from Boiler 4 by ALSTOM's Power Plant Laboratories. The objective was to determine the cause of failure. Examination results showed that creep failure and creep damage were due to overheating caused by the lack of adequate cooling steam.
Visual & NDT Report for Boilers 4, 5, 6, 9, and 10	Alstom	**Boilers 4, 5, 6, 9, & 10**	C-0120025	Friday, November 23, 2001	This report details the inspection performed by Alstom in 2001 of the Generating Bank Tubes in Boilers 4, 5, 6, 9, & 10.

Balance of Plant

Report Title	Author and/or Company	Unit	Report No.	Date of Report	Scope of Report
DCS Plan	ABB	-	8869-1021	16-Jul-08	This report outlines the plan for the DCS in the plant with three phases: PCV upgrade, MPSIII Power Supply System upgrade, INFI-Net Loop Upgrade, and Engineering Tools upgrade.

STEWART MCKELVEY
LAWYERS • AVOCATS

65 Grafton Street, P.O. Box 2140
Charlottetown PE C1A 8B9 Canada tel: 902.892.2485 fax: 902.566.5283
stewartmckelvey.com

October 10, 2017

D. Spencer Campbell, Q.C.
Direct Dial: 902.629.4549
Direct Fax: 902.566.5283
scampbell@stewartmckelvey.com

PERSONAL & CONFIDENTIAL

Mr. Jason C. Roberts
Vice President, Finance & Chief Financial Officer
Maritime Electric Company, Limited
180 Kent Street, P.O. Box 1328
Charlottetown PE C1A 7N2

RECEIVED
OCT 10 2017

Dear Mr. Roberts:

Re: PEI – NB Interconnection Facilities
Our File No.: SM5093.111

Please find enclosed correspondence and enclosures from J. Gordon MacKay, Q.C., which is self-explanatory.

Should you have any questions or concerns, please do not hesitate to contact me.

Yours truly,

STEWART MCKELVEY

D. Spencer Campbell

DSC/mcd

Enclosures

351843 v1

CSM CARR, STEVENSON & MACKAY
BARRISTERS AND SOLICITORS

65 Queen Street
P.O. Box 522
Charlottetown
Prince Edward Island
C1A 7L1

Telephone: (902) 892-4156
Facsimile: (902) 566-1377
Web: www.csmlaw.com

RECEIVED
OCT 0 6 2017

October 5, 2017

DELIVERED

D. Spencer Campbell, Q.C.
Stewart McKelvey
65 Grafton Street
Charlottetown, PE

Dear Mr. Campbell:

Re: PEI-NB Interconnection Facilities

For your records and the records of your client Maritime Electric Company, Limited I enclose one fully executed original of each of the following documents:

1. The Interconnection Lease Agreement between the Province of Prince Edward Island, The Prince Edward Island Energy Corporation, and Maritime Electric Company, Limited effective as at July 1, 2017;

2. The Debt Collection Agreement between the Province of Prince Edward Island, The Prince Edward Island Energy Corporation, The City of Summerside, and Maritime Electric Company, Limited dated effective July 1, 2017.

Yours very truly,

CARR STEVENSON & MacKAY

J. GORDON MacKAY, Q.C.
JGM/id
Enc.

PEI-NB INTERCONNECTION FACILITIES

INTERCONNECTION LEASE AGREEMENT

BETWEEN

THE PROVINCE OF PRINCE EDWARD ISLAND

AND

THE PRINCE EDWARD ISLAND ENERGY CORPORATION

AND

MARITIME ELECTRIC COMPANY, LIMITED

JULY 2017

INTERCONNECTION LEASE AGREEMENT

THIS AGREEMENT made as at the 1st day of July 2017 (the "Effective Date"),

BETWEEN:

THE GOVERNMENT OF PRINCE EDWARD ISLAND, as represented by the Minister of Transportation, Infrastructure and Energy (hereinafter referred to as the "**Province**")

OF THE FIRST PART

- AND -

THE PRINCE EDWARD ISLAND ENERGY CORPORATION, a body corporate, established pursuant to section 2 of the *Energy Corporation Act*, R.S.P.E.I. 1988, Cap. E-7, as represented by its Chief Executive Officer (hereinafter referred to as the "**Energy Corporation**")

OF THE SECOND PART

- AND -

MARITIME ELECTRIC COMPANY, LIMITED, a body corporate, incorporated under the Canada Business Corporations Act, R.S.C 1985, c. C-44, as represented by its President and Chief Executive Officer (hereinafter referred to as "**MECL**")

OF THE THIRD PART

WHEREAS the Province owns a nominal 200-MW interconnection from Island Terminal #1 to Mainland Terminal #1 (hereinafter referred to as Interconnection #1);

AND WHEREAS the Energy Corporation owns a nominal 360-MW interconnection from Island Terminal #2 to Mainland Terminal #2 (hereinafter referred to as Interconnection #2);

AND WHEREAS MECL is a public utility as defined in the *Electric Power Act,* R.S.P.E.I 1988, Cap. E-4 (the "Act") with a franchise to produce, transmit, distribute and furnish electric energy in Prince Edward Island;

AND WHEREAS the Parties wish to cooperate such that the Interconnection Facilities are operated and maintained in accordance with Good Utility Practice for the benefit of the electric power consumers of the Province of Prince Edward Island and other transmission users as the case may be;

AND WHEREAS the Province and MECL have an existing interconnection lease agreement for Interconnection #1, which concerns the operation and maintenance of the interconnection, among other things;

AND WHEREAS MECL will surrender the said lease agreement for Interconnection #1;

AND WHEREAS this Agreement supersedes the existing interconnection lease agreement, concerning Interconnection #1, between the Province and MECL;

Now Therefore this Agreement Witnesseth that the Parties to this Agreement, in consideration of the mutual covenants and agreements contained herein, hereby covenant and agree as follows:

Article 1 – Definitions

1.1 The terms defined in this Section 1.1 shall have, for all purposes of this Agreement, the following meanings:

(i) **"Agreement"** means this instrument governing the operation and maintenance of the Interconnections as may be amended from time to time, and the expressions, "herein", "hereto", "hereof", "hereby", "hereunder" and similar expressions referred to in this instrument shall refer to the instrument hereto as so defined and not to any particular article, section, subsection or other subdivision hereof;

(ii) **"Applicable Laws"** means all laws, statutes, bylaws, rules, directives, policies, codes, regulations, treaties, requirements, standards, orders and decrees of, or issued by, any Authority, as may be amended from time to time, that are applicable to, and that are legally binding on or in respect of, the Parties and this Agreement, and any matter or thing related to or in respect of any of them, or any other matter or thing arising under or in respect of this Agreement, including under the common law and equity, to the extent applicable;

(iii) **"Authority"** means each and every government, governmental agency, authority, bureau or department, court, or other entity or instrumentality, as practicable, having legal jurisdiction;

(iv) **"Capital Addition"** means any addition of facilities which consists of one or more Units of Property made upon the mutual agreement of the Owners and MECL, following the In-Service Date as may be necessary to retain and/or to increase the capacity of the Interconnection;

(v) **"Capital Replacement"** means any addition of facilities which is made to take the place of any part of the Interconnection Facilities removed from service made upon the mutual agreement of the Owners and MECL and which consists of one or more Units of Property;

(vi) **"Commission"** means the Prince Edward Island Regulatory and Appeals Commission as established under the *Island Regulatory and Appeals Commission Act,* R.S.P.E.I. 1988, Cap. I-11;

(vii) **"Contingency Fund"** means a fund for Capital Replacements created from payments by MECL, established in accordance with Section 9.1;

(viii) **"Cost of Acquisition"** means the value of the land being conveyed from MECL to the Energy Corporation as per Section 6.1, and includes the current value of the land as determined by an appraiser appointed with the mutual agreement of MECL and the Energy Corporation, commissions, legal and survey expenses incurred in connection with the lands, real property taxes paid in respect of the lands and any other charges incidental thereto;

(ix) **"Debt"** has the meaning ascribed in the Debt Collection Agreement;

(x) **"Debt Collection Agreement"** means the agreement between MECL, Summerside, the Province and the Energy Corporation dated July 2017 which concerns repayment of the Initial Capital Cost;

(xi) **"External Arbitration Procedures"** shall have the meaning ascribed in Section 21.2;

(xii) **"Force Majeure Event"** means an event beyond the reasonable control of the Party affected including the following events (to the extent beyond the reasonable control of the Party affected by the event):

a) an act of God or the public enemy;
b) restrictive governmental laws or regulations;
c) an order of a court or tribunal of competent jurisdiction;
d) freight or other embargoes, inability to obtain fuel, power, raw materials, equipment or transportation;
e) casualty, fire, floods, tidal waves, earthquake, storm, hurricane, tornado, winds in excess of operating limits, slides;
f) epidemics, quarantine restrictions;
g) war, declared or undeclared, acts of terrorism, revolution, riots, insurrections, hostilities, civil disturbances, blockades, explosions;
h) strikes, walk-outs, work stoppages, lockouts, railroad obstructions, stoppages of labour, deliberate work slowdowns, other labour difficulties other than the unavailability of labour; or
i) any similar cause or circumstance beyond the reasonable control of the Party affected when claiming suspension which makes impracticable the fulfillment of its obligations hereunder and which by exercise of due diligence the Party is unable to prevent or overcome, but not including any event arising from lack of funds;

(xiii) **"Good Utility Practice"** means those project management, design, procurement, construction, operation, maintenance, repair, removal, and disposal practices, methods and acts that are engaged in by a significant portion of the electric utility industry in Canada during the relevant time period, or any other practices, methods or acts that, in the exercise of reasonable judgment in light of the facts known at the time a decision is made, could have been expected to accomplish a desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be the optimum practice, method, or act to the exclusion of others, but rather to be a spectrum of acceptable practices, methods or acts generally accepted in such electric utility industry for the project management, design, procurement, construction, operation, maintenance, repair, removal and disposal of electric utility facilities in Canada. Notwithstanding the foregoing references to the electric utility industry in Canada, in respect solely of Good Utility Practice regarding subsea alternating current transmission cables, the standards referenced shall be the internationally recognized standards for such practices, methods, and acts generally accepted with respect to subsea alternating current transmission cables. Good Utility Practice shall not be determined after the fact in light of the results achieved by the practices, methods or acts undertaken but rather shall be determined based upon the consistency of the practices, methods or acts when undertaken with the standard set forth in the first two sentences of this definition at such time;

(xiv) **"Initial Capital Cost"** means, for purposes of this Agreement, the aggregate of all the costs of construction and commissioning of Interconnection #2 and associated parts of the NB Interconnection Transmission incurred by the Energy Corporation, net of funding received from the Government of Canada, up to the In-Service Date, including interest actually paid by the Energy Corporation from the time planning for construction began until the In-Service Date, plus any costs incurred for the construction and commissioning of Interconnection #2 and associated parts of the NB Interconnection Transmission incurred by the Energy Corporation after signing of this Agreement;

(xv) **"In-Service Date"** means July 1, 2017;

(xvi) **"Interconnection Abandonment"** means the abandonment of the Interconnection Facilities, where, as a result of submarine cables or other facilities being degraded, destroyed or damaged to an extent rendering repairs impractical or uneconomic, or being otherwise involuntarily removed from the possession and control of the Owners and MECL, the Owners and MECL mutually agree not to replace them;

(xvii) **"Interconnection #1"** means all facilities, equipment, apparatus, transmission lines and structures of every kind and nature required for and used in connection with the transmission of electric power and energy from Mainland Terminal #1 to

Island Terminal #1 and existing at the In-Service Date, including but not limited to:

(a) Two, three conductor, 138 kV submarine cables having an approximate capacity of 200 MW, cable termination stations in NB and in PEI to change the mode of transmission from submarine cable to overhead conductor and to permit switching of cable circuits and 138 kV overhead transmission lines from such stations to the Mainland Terminal #1 and Island Terminal #1 respectively;

(b) Transmission, switching, control and metering facilities and compensation devices which may be required to transmit power from the Mainland Terminal #1 to Island Terminal #1 and vice versa; and

(c) All facilities, equipment, apparatus, structures and land required for the operation of all such facilities, including electric signs, markers and other necessary warnings to navigation and located between the Mainland Terminal #1 and Island Terminal #1;

(xviii) **"Interconnection #2"** means all facilities, equipment, apparatus, transmission lines and structures of every kind and nature required for and used in connection with the transmission of electric power and energy from Mainland Terminal #2 to Island Terminal #2 and existing at the In-Service Date including but not limited to:

(a) two, three conductor, 138 kV submarine cable systems having an approximate capacity of 360 MW, cable termination stations in NB and in PEI to change the mode of transmission from submarine cable to overhead conductor and to permit switching of cable circuits and 138 kV overhead transmission lines from such stations to Mainland Terminal #2 and Island Terminal #2 respectively;

(b) Transmission, switching, control and metering facilities and compensation devices which may be required to transmit power from Mainland Terminal #2 to Island Terminal #2 and vice versa; and

(c) All facilities, equipment, apparatus, structures and land required for the operation of all such facilities, including electric signs, markers and other necessary warnings to navigation and located between Mainland Terminal #2 and Island Terminal #2;

(xix) **"Interconnection Committee"** means the committee constituted under Article 8;

(xx) **"Interconnection Facilities"** means Interconnection #1 and Interconnection #2 or parts thereof;

(xxi) **"Island Terminal #1"** means the point at which the Interconnection Facilities transition to transmission facilities owned by MECL in Bedeque, PEI, which shall be the PEI side bushings of the line Y101 and Y103 circuit breakers as shown in Appendix A;

(xxii) **"Island Terminal #2"** means the point at which the Interconnection Facilities transition to transmission facilities owned by MECL in Borden-Carleton, PEI, which shall be where the overhead transmission line deadend insulator connects to the station structure, or where the underground cable pothead connects to overhead station infrastructure, as the case may be, as shown in Appendix B;

(xxiii) "**Mainland Terminal #1**" means the point at which the cable system transitions to transmission facilities owned by NB Power in Murray Corner, NB;

(xxiv) "**Mainland Terminal #2**" means the point at which the cable system transitions to transmission facilities owned by NB Power in Cape Tormentine, NB;

(xxv) **"NB"** means the Province of New Brunswick;

(xxvi) "**NB Interconnection Transmission**" means the transmission facilities in New Brunswick that are owned by NB Power and are designated as direct assignment facilities in accordance with the NB Power Open Access Transmission Tariff and by agreement between NB Power, MECL and Owners;

(xxvii) **"NB Power"** means the New Brunswick Power Corporation;

(xxviii) "**OATT"** means MECL's Open Access Transmission Tariff as approved by the Commission under Section 20 of the *Electric Power Act*, R.S.P.E.I. 1988, Cap. E-4, or a successor transmission system access tariff as the case may be;

(xxix) "**Operation and Maintenance License Agreement**" means an agreement entered into between Her Majesty The Queen in Right of Canada, Her Majesty The Queen in Right of Prince Edward Island, Her Majesty The Queen in Right of New Brunswick and The Prince Edward Island Energy Corporation and Maritime Electric Company, Limited, and entitled "Operations and Maintenance License Agreement for PEI-NB Cable Interconnection Upgrade Project";

(xxx) **"Owner" or "Owners"** means the Province and the Energy Corporation, jointly or severally;

(xxxi) "**Party**" means either the Corporation or MECL and "**Parties**" refers to both the Corporation and MECL;

(xxxii) **"PEI"** means the Province of Prince Edward Island;

(xxxiii) "**Rate Base**" means the maximum valuation of assets fixed by the Commission pursuant to the *Electric Power Act* R.S.P.E.I. 1988, Cap E-4 upon which MECL may earn a percentage of return established by the Commission or another method of computing the maximum return as determined by the Commission;

(xxxiv) "**Rent**" shall mean the Rent payable by MECL to the Owners pursuant to Article 4.0 hereof and in addition thereto an amount shall be paid to build up a Contingency Fund to cover Capital Replacements as hereinafter provided;

(xxxv) "**Service Life**" means the period during which the Interconnection and Capital Additions and Capital Replacements thereto are, by mutual agreement of the parties hereto, capable of being operated economically to transfer electric power and energy;

(xxxvi) "**Subsequent MECL Capital Costs**" means the aggregate cost of Capital Replacements and/or Capital Additions incurred by MECL after the In-Service Date (including interest during construction) which are paid for by MECL;

(xxxvii) "**Summerside**" means the City of Summerside;

(xxxviii) "**Term**" shall have the meaning ascribed in Article 3;

(xxxix) "**Transmission Users**" means a 'Transmission Customer' as defined in the OATT who takes 'Transmission Service' as defined in the OATT;

(xl) "**Unit of Property**" means the smallest item of property which is separately written into the Interconnection Facilities plant account.

<u>Article 2 - Agreement to Lease</u>

2.1. Following the In-Service Date, the Owners will retain ownership of the Interconnection Facilities but lease and deliver administration and operational control of the Interconnection Facilities to MECL. MECL shall operate, repair and maintain the Interconnection Facilities in accordance with Good Utility Practice on behalf of the Owners at MECL's expense throughout the Service Life.

2.2 The lease does not include fibre optic cables included in the construction of the submarine cable system of Interconnection #2 except to the extent necessary for the operation and monitoring of the Interconnection Facilities.

2.3. In the event that MECL uses only a portion of the available fibre optic cable capacity located within Interconnection #2 for the operation and monitoring of the Interconnection Facilities, and in the event that MECL requires the use of additional fibre optic capability located within Interconnection #2 for the operation and monitoring of the Interconnection Facilities whether due to damage to existing fibre optic facilities or requirement for expansion of capabilities, the Owner shall make such fibre optic capability available to MECL at no charge within the timeframe prescribed by MECL so as to continue the safe and reliable operation of the Interconnection Facilities.

<u>Article 3 – Term of Agreement</u>

3.1 The term of this Agreement shall be for the duration of the Service Life. This Agreement shall commence on the In-Service Date.

Article 4– Rent

4.1 Rent payable hereunder shall be the sum of one ($1.00) dollar of lawful money of Canada by MECL to the Owner payable annually on the anniversary date of this Agreement. (It being understood and agreed that the failure of MECL to pay the basic rent of $1.00 in any year shall not entitle the Owner to terminate this Agreement unless notice of default in payment of basic rent is given in writing by the Owner to MECL and MECL has not rectified such default within 15 days of notice).

4.2 Should Interconnection Abandonment occur, then all Rent due to the Owner shall terminate on the date MECL commissions replacement generation in order to meet the electric power requirements of its customers and shall not resume unless the Parties mutually agree to return the Interconnection Facilities to service. Replacement generation is understood to mean adequate emergency capacity. MECL will proceed to install additional capacity as required in order to provide reserve capacity in accordance with Good Utility Practice.

Article 5– Operation, Maintenance and Repairs

5.1 Commencing on the In-Service Date, MECL shall operate, maintain and repair the Interconnection Facilities in accordance with Good Utility Practice.

5.2 MECL shall undertake such operation, maintenance and repairs of the Interconnection Facilities as required and as is consistent with MECL's repairs and maintenance of its own facilities in accordance with Good Utility Practice and in consultation with the Owners.

5.3 MECL shall undertake all clean up, reporting and restoration on behalf of the Owner in response to a release of any hazardous product to the environment from the Interconnection Facilities in a manner consistent with MECL's clean up, reporting and restoration for similar releases from its own facilities.

5.4 In the event that the Interconnection Facilities require actions to be undertaken as per Sections 5.2 and 5.3, and in the event that these actions, in MECL's opinion, have to be taken in an urgent or emergency situation and MECL attempts to consult with, and receive prior approval from, the Owners for the required actions but cannot do so in a timely manner, MECL shall respond to the urgent or emergency situation, without Owner consultation and prior approval, with operating, maintenance and repair actions in accordance with Good Utility Practice, or in a manner consistent with MECL's clean up, reporting and restoration for similar situations involving its own facilities, as the case may be.

5.5 MECL shall inform the Owners of actions undertaken in Section 5.4 as soon as reasonably possible.

5.6 MECL agrees to accept sole responsibility to submit any applications, reports, payments or contributions for sales taxes, income tax, Canada Pension Plan, Employment Insurance, Workers' Compensation assessments, goods and services tax, harmonized sales tax, or any other similar matter which MECL may be required by law to make in connection with the operation, maintenance and repairs performed under this Agreement.

5.7 MECL agrees to accept sole responsibility to comply with all Applicable Laws which may have application to the operation, maintenance and repairs performed by MECL under this Agreement and without limiting the generality of the foregoing agrees to comply with all provincial and federal legislation affecting conditions of work and wage rates including the *Employment Standards Act* R.S.P.E.I., 1988 Cap. E-2, the *Workers Compensation Act* R.S.P.E.I., 1988 Cap. W-7 and similar applicable legislation in the Province of New Brunswick or any other laws that impose obligations in the nature of the employers' obligations.

5.8 MECL agrees that it shall operate and maintain the Interconnection Facilities in accordance with and in compliance with the Operation and Maintenance License Agreement.

Article 6 – Land

6.1 Land already vested in MECL which is, in the opinion of the Owners and MECL, necessary or necessarily incidental to the construction and operation of Interconnection #2, shall be conveyed to Energy Corporation at the Cost of Acquisition thereof by MECL to become part of Interconnection #2.

6.2 Lands in PEI which are required for the construction, operation, maintenance and use in common of both MECL owned transmission facilities and the Interconnection Facilities including any additions thereto shall remain vested in MECL.

6.3 MECL shall grant to the Energy Corporation rights of way across lands in PEI which are already vested in MECL and that are necessary for accessing Interconnection #2 by means of foot or vehicle.

Article 7 – Summerside and MECL Rights to Interconnection Capacity

7.1 The Interconnection Facilities are part of the MECL Transmission System.

7.2 MECL and Summerside are contributing to the Initial Capital Cost and the associated parts of the NB Interconnection Transmission as set out in the Debt Collection Agreement.

7.3 The Parties agree that MECL and Summerside will share the import capacity from NB to PEI of the Interconnection Facilities based on each of MECL's and Summerside's ratio of contributions towards the Debt.

7.4 The Parties agree that, as per the Debt Collection Agreement, Summerside's percentage of the average 12 month coincident peak demand of electrical consumption in the PEI during the years 2012 through 2016 averaged 10.1%, and consequently for the years 2017 through 2021 inclusive Summerside shall be entitled to the same 10.1% of import capacity from NB to PEI across the Interconnection Facilities, provided it duly contributes said similar percentage of the Initial Capital Cost and the associated parts of the NB Interconnection Transmission as per the Debt Collection Agreement.

7.5 The Parties agree that, as per the Debt Collection Agreement, MECL's percentage of the average 12 month coincident peak demand of electrical consumption in the PEI during the years 2012 through 2016 averaged 89.9%, and consequently for the years 2017 through 2021 inclusive MECL shall be entitled to the same 89.9% of import capacity from NB to PEI across the Interconnection Facilities, provided it duly contributes said similar percentage of the Initial Capital Cost and the associated parts of the NB Interconnection Transmission as per the Debt Collection Agreement.

7.6 The Parties agree that each of MECL's and Summerside's relative assured access to the import capacity from NB to PEI across the Interconnection Facilities may change during the Term as per the Debt Collection Agreement.

Article 8 – Interconnection Committee

8.1 A committee to be known as the Interconnection Committee shall be established within 30 days of the Effective Date, consisting of one representative from each of the Province, Energy Corporation, MECL, and Summerside for the following purposes:

i) the Interconnection Committee will meet on a semi-annual basis to review the operation, maintenance and cost report prepared by MECL and to receive updates on the condition of the assets and inspection reports.

ii) the Interconnection Committee will provide oversight as to the operation and maintenance of the Interconnection Facilities and in particular, contemplated Capital Additions or Capital Replacements, it being recognized that the Interconnection Committee exists principally for the sharing of information regarding the Interconnection Facilities, and also recognizing that ultimate control over the Interconnection Facilities vests in the Owners as per the terms of this Agreement.

8.2 The Interconnection Committee is not authorized to modify or amend any terms of this Agreement. While members of the Interconnection Committee may incur expenses that result from the Interconnection Committee's activities in accordance with this Agreement, the Interconnection Committee has no authority to commit or otherwise contractually bind any of the members of the Committee to directly incur or pay any cost or expenditure.

8.3 Energy Corporation shall prepare the agenda for the meetings which shall include matters specified by any of the representatives on the Interconnection Committee. The agenda shall be settled and circulated fourteen days prior to the semi-annual meetings. Special meetings of the Interconnection Committee may be called at any time by the Energy Corporation representative on the Committee or at the request of two or more of the other Committee members.

8.4 Matters to be included in the agenda for discussion at a meeting of the Interconnection Committee shall include but not be limited to the following:

a) amending, adding, or cancelling schedules;

b) assessment of compliance with the terms of this Agreement;

c) preparation, documentation, retention and distribution of Interconnection Committee minutes and agendas as prepared by or on behalf of the Energy Corporation; and

d) discussion for the purpose of input into the development and implementation of decisions involving but not limited to the following work activities:
(i) development and maintenance of procedures for active power and reactive power accounting, including but not limited to methods of energy balancing;
(ii) approval of information and data exchange costs and scope;
(iii) documented points of operational data, as required by mutual agreement;
(iv) development and maintenance of outage scheduling and coordination procedures with respect to the reliable operation of the Interconnection Facilities;
(v) coordination of system tests;
(vi) development of system restoration and mutual assistance procedures; and
(vii) approval of required Capital Additions and Capital Replacements, Interconnection Abandonment, and Operation and Maintenance License Agreement.

Article 9 – Capital Replacements

9.1 In addition to basic rent there shall be a contribution paid by MECL to an account known as the Contingency Fund, which contribution shall be collected from Transmission Users in accordance with the provisions of the OATT. The contribution shall be $300,000 annually between March 1, 2017 and February 28, 2019. Commencing March 1, 2019 the rate shall increase to $375,000 annually. MECL shall be required to contribute to the Contingency Fund when the Contingency Fund has a balance of less than $5,000,000, and shall not be required to contribute to the Contingency Fund when the Contingency Fund has reached its maximum balance of $5,000,000.

9.2 The Contingency Fund shall be deposited with a Canadian chartered bank in an interest bearing investment (the "Fund") as a trust fund from which Capital Replacements will be made as follows:

(a) Capital Replacements will be made from the Fund up to the amount of the Fund;

(b) Capital Replacements of a cost greater than the amount in the Fund will be subject to agreement between the Owner and MECL, and if paid for by MECL will be considered to be a Subsequent MECL Capital Cost to be included in Rate Base and collected from Transmission Users in accordance with the provisions of the OATT as submitted from time to time by MECL for approval by the Commission;

(c) The Owner and MECL must agree to make any necessary Capital Replacement or Interconnection Abandonment will be deemed to have occurred.

9.3 A list of Units of Property shall be agreed to by the Parties hereto prior to the In-Service Date and shall be in accordance with Good Utility Practice.

9.4 Based on future experience on Capital Replacements and on escalation, the maximum of $5 Million in the Contingency Fund may be increased or decreased by mutual agreement between the Parties and there may be a minimum established by mutual agreement which will be left in the Fund to take care of small Capital Replacements from time to time.

9.5 If Interconnection Abandonment occurs or at the end of the Service Life of the Interconnection Facilities, any balance remaining in the Contingency Fund shall be used for decommissioning.

9.6 The Contingency Fund shall be owned and controlled by the Province and payments from the Fund will be made by the Province.

9.7 All Capital Replacements shall be free and clear of all liens and rights of others and shall be in as good operating condition as, and shall have a value and utility at least equal to, the parts replaced assuming such replaced parts were in the condition and repair required to be maintained by the terms hereof.

9.8 MECL shall make annual contributions as aforesaid, in the amounts of $300,000 or $375,000 as the case may be, to the Fund as necessary to build the Fund to $5 Million or replace any amount withdrawn from the Fund for the purposes for which the Fund was established.

<u>Article 10– Capital Additions</u>

10.1 Upon mutual agreement of the Owners and MECL, Capital Additions may be made to the Interconnection Facilities from time to time.

10.2 If such Capital Additions are agreed upon and made as herein before provided, the Owners shall have the option to:

(a) purchase and install such Capital Additions and to lease the same to MECL on the same terms and conditions, as are applicable, as set out in this Agreement, and MECL agrees to pay the Owners on account together with Summerside either (i) under an agreement similar to the Debt Collection Agreement, or (ii) by revising the existing Debt Collection Agreement; or

(b) direct MECL to purchase and install such Capital Additions with the Subsequent MECL Capital Costs to be included in Rate Base and collected from Transmission Users in accordance with the provisions of the OATT as submitted from time to time by MECL for approval by the Commission.

Article 11 – Benefits of Suppliers' Guarantees

11.1 If any appliances, parts, instruments, appurtenances, accessories, furnishings and other equipment of whatever nature are found to be defective while still under the supplier's guarantee or warranty, the benefits of such supplier's guarantee or warranty, if any, shall accrue as follows if:

(a) such benefits are in lieu of replacement of the defective part, such benefit shall accrue to MECL who shall apply such benefit to the replacement of such defective part; or if

(b) such benefit is due to a penalty levied against a supplier under a contract with such supplier, such benefit shall accrue to the Owners and be used for the operation, maintenance, repair or financing of the Interconnection Facilities.

Article 12 - Billing and Payment

12.1 The operation, maintenance and repair of the Interconnection Facilities undertaken by MECL in Sections 5.1 and 5.2 shall be performed on behalf of the Owners, and shall be at the cost of MECL.

12.2 The clean up, reporting and restoration of the Interconnection Facilities undertaken by MECL in Section 5.3 in response to a release of any hazardous product to the environment from the Interconnection Facilities shall be performed on behalf of the Owners, and shall be at the cost of MECL.

12.3 Subject to the approval of the Commission, MECL shall include the costs that it incurs for the operation, maintenance, repair, clean up, reporting and restoration of the Interconnection Facilities as per Sections 12.1 and 12.2 in its annual revenue requirement and MECL shall collect the costs from Transmission Users in accordance with the provisions of the OATT.

12.4 Subject to the approval of the Commission, MECL shall be entitled to include the costs it incurs for undertaking urgent or emergency actions at the Interconnection Facilities as per Section 5.4 in its annual revenue requirement. In the event the Commission does not approve all or any part of the costs incurred by MECL under this Agreement then the unapproved costs shall be considered a Capital Replacement.

12.5 It is the intention of the Parties that in performance of this Agreement MECL will not incur any material costs or material increase in any costs that it would not otherwise incur for which it is not compensated under Section 12.4, other than internal costs incurred in the administration of this Agreement and in performing its obligations hereunder.

<u>Article 13- Ownership</u>

13.1 Nothing in this Agreement is intended to create, or shall create, in favour of MECL or its successors and assigns, any legal title of any nature whatsoever in the property comprising the Interconnection Facilities.

13.2 Nothing contained herein shall be construed as creating a partnership, joint venture or association of any kind.

13.3 (a) The Parties agree that MECL shall act as an independent contractor and that it is entitled to no other benefits or payments whatsoever than those specified in this Agreement.

(b) The Parties agree that entry into this Agreement will not result in the appointment or employment of MECL, or any officer, clerk, employee or agent of MECL, as an officer, clerk, employee or agent of the Province or the PEI Energy Corporation, nor shall the *Civil Service Act*, R.S.P.E.I. 1988, Cap. C-8 apply.

<u>Article 14 – Indemnification</u>

14.1 Indemnification Obligation

Subject to the limitations on and exclusions of liability set forth herein, each Party agrees to indemnify, hold harmless, and defend the other Party, its affiliates, and their respective officers, directors, employees, agents, contractors, subcontractors, invitees and successors (collectively the indemnitees), from and against any and all claims, liabilities, costs, damages, and expenses which may be imposed on or asserted at any time against an indemnitee by any third party (including, without limitation, reasonable attorney and expert fees, and disbursements incurred by any indemnitee in any action or proceeding) for or arising from damage to property, injury to or death of any person, including the other Party's employees or any third parties (collectively, the loss), to the extent caused wholly or in part by any act or omission, negligent or otherwise, by the indemnifying Party and/or its officers, directors, employees, agents, and subcontractors arising out of or connected with the indemnifying Party's performance or breach of this Agreement, or the exercise by the indemnifying Party of its rights hereunder; provided, however, that no indemnification by a Party is required under this section to the extent such loss is caused by or results from the negligence or willful misconduct of the other Party or its indemnitee(s). In the event that such loss is the result of the negligence of both Parties, each Party shall be liable to the other to the extent or degree of its respective negligence, as determined by mutual agreement of both Parties, or in the absence thereof, as determined by the adjudication of comparative negligence.

14.2 Control of Indemnification

If any third party shall notify any indemnitee of a claim with respect to any matter which may give rise to a claim for indemnification against the other Party (the indemnifying Party) under this section, then the indemnitee shall notify the indemnifying Party thereof promptly (and in any event within ten (10) business days after receiving any written notice from a third party). The indemnifying Party's liability hereunder to the indemnitee shall be reduced to the extent the indemnifying Party is materially adversely prejudiced by the indemnitee's failure to provide timely notice hereunder. In the event any indemnifying Party notifies the indemnitee within ten (10) business days after the indemnitee has given notice of the matter that the indemnifying Party is assuming the defense thereof, (i) the indemnifying Party will defend the indemnitee against the matter with counsel of its choice reasonably satisfactory to the indemnitee, (ii) the indemnitee may retain separate co-counsel at its sole cost and expense (except that the indemnifying Party will be responsible for the fees and expenses of the separate counsel to the extent the indemnitee reasonably concludes that the counsel the indemnifying Party has selected has a conflict of interest), (iii) the indemnitee will not consent to the entry of any judgment or enter into any settlement with respect to the matter without the written consent of the indemnifying Party (which shall not be unreasonably withheld, and (iv) the indemnifying Party will not consent to the entry of any judgment with respect to the matter, or enter into any settlement which does not include a provision whereby the plaintiff or claimant in the matter releases the indemnitee from all liability with respect thereto, without the written consent of the indemnitee (which shall not be unreasonably withheld). In the event the indemnifying Party does not notify the indemnitee within ten (10) business days after the indemnitee has given notice of the matter that the indemnifying Party is assuming the defense thereof, however, the indemnitee may defend against the matter in any manner it may deem appropriate.

14.3 Recovery of Enforcement Costs

Notwithstanding any other provision of this Agreement, the indemnifying party will pay all damages, settlements, expenses and costs, including costs of investigation, court costs and reasonable attorneys' fees and costs the other Party incurs in enforcing this Article 14. Each Party agrees its indemnification obligation, as detailed under this Article 14, will survive expiration or termination of the Agreement.

14.4 Limitations on Indemnity

Notwithstanding the foregoing, the Parties agree that should one Party be required to indemnify the other, overall liability by one Party to the other shall not exceed two million dollars ($2,000,000). The Parties also agree that the mutual indemnifications set out herein shall not extend to indemnification for indirect or consequential damages including loss of profit.

<u>Article 15 – Insurance</u>

15.1 MECL will, without cost to the Owner, maintain or have maintained in effect through the Term, the following insurance with independent and reputable insurers that (i) are licensed in NB and Prince Edward Island and (ii) have a rating of not less than A- from A.M. Best Company, which insurance shall be in such form and amounts and with such deductibles and subject to such exclusions as set forth below:

(a) insurance against loss or damage to the Interconnection Facilities from such risks and in such amounts as MECL would, in the prudent management of its properties, maintain or cause to be maintained with respect to similar equipment owned by it, due consideration being given to the probability that certain risks connected with the Interconnection Facilities are uninsurable. Notwithstanding the provisions of the foregoing sentence, however, MECL may self-insure against such risks by deductible provisions or otherwise if:

 (i) the Interconnection Facilities are self-insured to no greater extent than any similar equipment owned by MECL, and

 (ii) in the event of loss or damage affecting the Interconnection Facilities and property owned by MECL, no more than a pro rata portion of such self-insurance would be applicable to the Interconnection Facilities.

 Any insurance policies carried in accordance with this subsection (a) shall name Owner, as owner of the Interconnection Facilities, as an additional insured, and losses shall be made payable to Owner as its interest may appear provided, however, that such proceeds shall first be used by MECL to pay the costs of repair or replacement of the Interconnection Facilities.

(b) general liability insurance, including insurance against claims for personal injury, death, property damage and/or loss arising out of the operation of the Interconnection Facilities and extended to include coverage for contractual liability, contingent employer's liability, tenant's legal liability, owners'/contractors' protective liability, products and completed operations, collapse, explosion and underground hazards, limited pollution liability including coverage for sudden and accidental events, and non-owned automobile liability, all with a minimum combined single limit of Fifty Million Canadian Dollars (CDN$50,000,000) per occurrence. Such policy will have a deductible not greater than Two Hundred and Fifty Thousand Canadian Dollars (CDN$250,000) per occurrence;

 Any insurance policies maintained in accordance with this subsection (b) shall:

 (i) name Owner as an additional insured as owner of the Interconnection Facilities. Coverage effected under this subsection shall insure the Owner's interest regardless of any breach of or violation by MECL of any warranties, declarations or conditions contained in such policies;
 (ii) contain a waiver by the insurer or insurers of all rights of subrogation or indemnity or any other claim to which such insurer or insurers might otherwise be entitled against the Owner and/or the licensors that are party to the Operation and Maintenance Licence;
 (iii) contain a non-vitiation clause; and

(iv) contain a cross liability and severability of interest clause;

(c) watercraft and/or aircraft liability insurance if any aircraft and/or watercraft will be utilized in relation to the Interconnection Facilities for a limit of not less than Ten Million Canadian Dollars (CAD$10,000,000) per occurrence;

(d) on or before the In-Service Date and thereafter at intervals of not more than twelve months, MECL shall furnish Owner a Certificate of Insurance signed by the MECL's insurer or their broker confirming that the insurance then maintained by MECL complies with the terms hereof.

15.2 MECL shall arrange to provide the other Owner with current certificates of insurance, in a form and content reasonably acceptable to the Owner, evidencing the required insurance policies hereunder within ten (10) days of the Effective Date and on each renewal of the insurance policies thereafter, and which require that the Owner shall receive thirty (30) days written notice prior to cancellation during the term of the policy (with the exception of cancellation for non-payment of premium for which a statutory fifteen (15) days' notice may apply). Umbrella insurance may be used to achieve the required insured limits under Section 15.1 above.

15.3 If MECL fails to maintain the required insurance described herein, the Owner may, but has no obligation to, pay the premium therefore and obtain reimbursement from MECL. MECL's required insurance shall be primary except to the extent of claims arising from the negligence of a third party for whom MECL is responsible in law.

15.4 If MECL fails to maintain the insurance policies set out above, the Owner (after notice to, and failure to remedy) shall be entitled (but not obligated) to effect such insurance as it deems proper and MECL shall promptly reimburse the Owner all premiums paid by the Owner, together with any additional costs incurred by the Owner.

15.5 The Parties to this Agreement may, at all times during the Term, maintain in force separate and individual insurance policies, in addition to the obligations listed above, to fully protect that Party against any claims for property damage, personal injury or death which might arise out of the performance or non-performance of either Party's obligations under this Agreement for which either Party may be held liable, whether such legal obligation is based on an action in contract, tort, warranty or otherwise.

15.6 The policies required shall be in a form and with insurers satisfactory to the Owner. The foregoing insurance shall be primary, with the exception of Owner's negligence, and not require the sharing of any loss by any insurer of Government or any other means of indemnity such as the Prince Edward Island Self Insurance and Risk Management Fund. A certificate of insurance shall be delivered to the Owner prior to the signing of this agreement. Default of delivery or receipt by MECL shall not be construed as acknowledgment or concurrence that there has been compliance with the terms of this Agreement. The insurer shall acknowledge that the policy is primary and any other insurance policies that may be in effect or any other sources of recovery the including the

Corporation or Government of Prince Edward Island's Self Insurance and Risk Management Fund shall not contribute in any way to any judgments, awards, payments, or costs or expenses of any kind whatsoever made as a result of actual or alleged claims.

15.7 MECL agrees that the insurance provided herein no way limits MECL's liability pursuant to the indemnity provisions provided for in this Agreement.

15.8 In order to maintain the sufficient and appropriate insurance, the insurance requirements set out in this Article 15 shall be reviewed, and if necessary adjusted, by the Parties at least once every five (5) year period during the Term or earlier, if (a) there are changes in applicable regulatory requirements for insurance specifications or coverage; or (b) if acting reasonably a clear change in risk is identified by either Party.

Article 16 – Regulation

16.1 MECL's participation in this Agreement shall be subject to the approval of the Commission.

16.2 The Parties agree that this Agreement is subject at all times to review and revision by the Commission provided, however, that should any review or revision made by the Commission be material, a Party may invoke the dispute resolution procedures contained in Article 21 of this Agreement.

16.3 In the process of the regulation of the electric power and energy rates of MECL by the Commission, no part of the Initial Capital Cost, or Capital Addition and/or Capital Replacement costs that are paid for by the Owners, shall be included in the Rate Base as submitted from time to time by MECL for the approval of the Commission.

16.4 Any Subsequent MECL Capital Costs that are otherwise not collected from the Owners may be included in the Rate Base and collected from Transmission Users in accordance with the provisions of the OATT as submitted from time to time by MECL for approval by the Commission.

16.5 MECL shall not claim depreciation of any part of the Initial Capital Cost, or Capital Addition or Capital Replacement costs that are paid for by the Owners, as an operating expense.

Article 17 – Waiver of Subrogation

17.1 The Parties agree not to make any claim or take any other or further proceedings or actions against or on behalf of any person or corporation who might claim subrogation, contribution or indemnity against the other Party or any other person or under any statute or otherwise.

Article 18 - Termination of Agreement

18.1 At any time during the Term, the Parties may terminate this Agreement by mutual consent.

Article 19 - Force Majeure

19.1 Force Majeure Events

No Party shall be liable to another Party if performance under this Agreement is interrupted or delayed due to Force Majeure Event.

19.2 Notice of Force Majeure

Should either Party claim delay or interruption arising from the occurrence of an event of Force Majeure, prompt notice in writing thereof shall be given to the other Parties.

19.3 Reasonable Efforts

A Party, whose performance under this Agreement is hindered by an event of Force Majeure, shall make all reasonable efforts to perform its obligations under this Agreement.

Article 20 - Assignment of Agreement

20.1 No Party shall assign or delegate its rights and obligations hereunder without the prior written consent of the other Parties; provided, however, each Party may, without consent of each other Parties (but without relieving itself from liability hereunder), either:

(i) transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements, or

(ii) transfer or assign and delegate this Agreement to any person or entity succeeding to all or substantially all of the assets of the assigning Party;

provided, however, that in each case, any assignee (or, in the case of an assignment pursuant to (i), any purchaser of substantially all of the property of a Party from such an assignee) must prior to exercising its rights under this Agreement agree in writing to be bound by the terms and conditions hereof in the place and stead of MECL, the Province or the Energy Corporation as the case may be.

Article 21 - Dispute Resolution

21.1 Internal Dispute Resolution Procedures

Any dispute between the Owners and MECL as to their rights under this Agreement shall be referred to a designated senior representative of the Owners and a senior representative of MECL's Agent for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) business days (or such other period as the Parties may agree upon) by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

21.2 External Arbitration Procedures

Any arbitration initiated under this Agreement shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) business days of the referral of the dispute to arbitration, each party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) business days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any Party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the *Arbitration Act*, R.S.P.E.I. 1988, Cap. A-6 and any applicable Commission rules or regulations.

21.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Agreement and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction.

21.4 Costs

Each party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(i) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(ii) one half of the cost of the single arbitrator jointly chosen by the Parties.

In the event that it is necessary to enforce such award, all costs of enforcement shall be payable and paid by the Party against whom such award is enforced.

21.5 Referral of Dispute to the Commission

Notwithstanding anything contained in this Article 21, either Party may, instead of proceeding through the External Arbitration Procedures outlined in Section 21.2 above, request the Commission hear and decide the dispute by filing a complaint with the Commission pursuant to the *Electric Power Act*, R.S.P.E.I. 1988, Cap. E-4, in the manner set out below and the decision of the Commission with respect to the matter shall be final and binding and the matter in dispute cannot thereafter proceed to the dispute resolution process. Complaints filed with the Commission must be in writing and must include reasons and evidence in support of the dissatisfied Party's position. A copy of the complaint, together with the supporting reasons and evidence, must be filed with the other Party or Parties.

The Commission may require a complainant to provide such security for the costs incurred or to be incurred by the Commission, as it considers reasonable, and such security may be forfeited to the Commission if the complaint is not substantiated.

21.6 Enforcement of Arbitration Decision

The *Arbitration Act*, R.S.P.E.I. 1988, Cap. A-6 shall govern the procedures to apply in the enforcement of any award made pursuant to Section 21.3.

Article 22 -Representations and Warranties of the Owners

22.1 The Province and the Energy Corporation represent and warrant to MECL that: (i) the Energy Corporation is a body corporate, validly existing, and in good standing under the laws of PEI; (ii) the Owners have all necessary corporate power, authority and capacity to enter into this Agreement and to carry out its obligations under this Agreement and that the execution, delivery and performance of this Agreement have been duly authorized by all necessary corporate or administrative action of the Owners; (iii) there is no claim, action, proceeding or other litigation pending or, to the knowledge of the Owners threatened, which, if adversely determined, would restrict or otherwise interfere in any material respect with the obligations of the Owners under this Agreement; (iv) this Agreement constitutes a legal, valid and binding obligation of the Owners enforceable against the Owners in accordance with its terms, subject as to enforcement limits imposed by bankruptcy, insolvency or similar laws affecting creditors' rights generally and the availability of equitable remedies.

22.2 The execution and delivery of this Agreement by the Owners and the performance of these obligations contained herein will not result in the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the acceleration of any obligation of the Owners under: (i) any contract, agreement, instrument or other document to which the Province or the Energy Corporation is a party or by which it or its properties or assets are bound; (ii) the constating documents of the Energy Corporation; (iii) any judgment, decree, order or award of any government agency having jurisdiction over the Province or the PEI Energy Corporation; (iv) any license, permit, approval, consent or authorization held by or for the benefit of the Province or the Energy Corporation; or (v) any applicable law, statute, ordinance, regulation or rule.

Article 23 - Representations and Warranties of MECL

23.1 MECL represents and warrants to the Owners that: (i) MECL is a body corporate and is validly existing and in good standing under the laws of Canada; (ii) MECL has all necessary power, authority and capacity to enter into this Agreement and to carry out its obligations under the Agreement and that the execution, delivery and performance of this Agreement have been duly authorized by all necessary action of MECL; (iii) there is no claim, action, proceeding or other litigation pending or, to the knowledge of MECL threatened, which, if adversely determined, would restrict or otherwise interfere in any material respect with the obligations of MECL under this Agreement; (iv) this Agreement constitutes a legal, valid and binding obligation of MECL enforceable against MECL in accordance with its terms, subject as to enforcement limits imposed by bankruptcy, insolvency or similar laws affecting creditors' rights generally and the availability of equitable remedies.

23.2 The execution and delivery of this Agreement by MECL and the performance of its obligations contained herein will not result in the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the acceleration of any obligation of MECL under: (i) any contract, agreement, instrument or other document to which MECL is a party or by which it or its properties or assets are bound; (ii) the constating documents of MECL; (iii) any judgment, decree, order or award of any government agency or tribunal having jurisdiction over MECL ; (iv) any license, permit, approval, consent or authorization held by or for the benefit of MECL; or (v) any applicable law, statute, ordinance, regulation or rule.

Article 24 - Notice

24.1 Where in this Agreement any notice, payment, request, direction, or other communication is required to be given or made by any Party to another Party, it shall be in writing and is effective if delivered in person, sent by registered mail or by facsimile addressed to the Party for whom it is intended at the address so described in this Article and any notice, request, direction or other communication shall be deemed to have been given if by registered mail, when the postal receipt is acknowledged by the other Party; or by facsimile when transmitted.

24.1.1 The address for notice, payment, request, direction, or other communication for MECL shall be:

Maritime Electric Company, Limited
180 Kent Street
P.O. Box 1328
Charlottetown, PE C1A 7K7

Attention: Vice President, Corporate Planning & Energy Supply
Fax: (902) 629-3665

24.1.2 The address for notice, payment, request, direction, or other communication for the Government of Prince Edward Island shall be:

Department of Transportation, Infrastructure and Energy
11 Kent Street, 3rd Floor
P.O. Box 2000
Charlottetown, PE C1A 7N8

Attention: Minister
Fax: (902) 868-5385

24.1.3 The address for notice, payment, request, direction, or other communication for the PEI Energy Corporation shall be:

The Prince Edward Island Energy Corporation
16 Fitzroy Street
P.O. Box 2000
Charlottetown, PE C1A 7N8

Attention: Chief Executive Officer
Fax: (902) 894-0290

24.2 The address of any Party may be changed by notice in accordance with the procedure described in Section 24.1.

Article 25 - Confidentiality and Copyright

25.1 Any and all information, knowledge or data made available to either Party by the other as a result of this Agreement shall be treated as confidential information. Neither Party will directly or indirectly disclose or use this information, knowledge or data or the products that arise from the information, knowledge or data for purposes unrelated to this Agreement at any time without first obtaining the written consent of the other, unless the information, knowledge or data is generally available to the public.

25.2 The Parties agree that all lists, reports, information, statistics, compilations, analyses, and other data generated or collected in any way as a result of this Agreement are the exclusive property of the Owners and shall not be distributed, released, transmitted or used in any way, via any media, outside the purposes of this Agreement, by MECL, its employees, agents, servants or others for whom MECL is responsible, without the written consent of the Owners.

25.3 The Parties acknowledge that they may wish to make public announcements about the existence of certain parts of this Agreement. If MECL is the Party advocating publicity through any medium, MECL will provide the Owners with the date and time of any proposed release of information, as well as a copy of such information proposed to be released, for review and assessment by the Owners, at least ten (10) days prior to the scheduled public release. All promotional materials and arrangements for public release related to this Agreement must be approved by the Owners prior to any public release.

Article 26 – Freedom of Information and Protection of Privacy Act

26.1 The Parties acknowledge that this Agreement, and any information pursuant to it, may be subject to release under the *Freedom of Information and Protection of Privacy Act*, R.S.P.E.I. 1988, Cap. F – 15.01, (the "Act"). MECL shall be contacted prior to the release of information in regards to this Agreement that may be required under the Act.

26.2 MECL acknowledges and agrees that, in the event this Agreement involves the collection or use of personal information, it is subject to the *Freedom of Information and Protection of Privacy Act*, and that personal information may not be released to any third party or unauthorized individual.

Article 27 - General

27.1 Headings

The division of this Agreement into articles and sections and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of the Agreement.

27.2 Extended Meanings

In this Agreement words importing the singular number only shall include the plural and *vice versa*, words importing the masculine gender shall include the feminine and neuter genders and *vice versa* and words importing persons shall include individuals, partnerships, associations, trusts, unincorporated organizations and corporations.

27.3 Applicable Laws

This Agreement shall be generally governed and interpreted in accordance with the laws in force in PEI and to the extent necessary the laws of NB and the laws of Canada applicable therein.

27.4 Survival of Agreement

This Agreement shall enure to the benefit of and be binding on the Parties and their respective successors and permitted assigns.

27.5 Audit

27.5.1 The Owners or their authorized representatives shall have the right at all reasonable times to audit, inspect, take extracts from, and make copies of records of MECL, on a confidential basis, relating to costs incurred by MECL.

27.5.2 MECL shall provide to the Owners such facilities as required for audit and inspection and shall furnish the authorized representatives of the Owners with such information as the Owners from time to time, acting reasonably, may require with reference to the documents and information referred to in Section 27.5.1.

27.5.3 MECL shall not dispose of the documents referred to in Section 27.5.1 herein without the written consent of the Owners, but shall preserve and keep them available for audit and inspection for a period of five (5) years following the date of each document.

27.6 Restructuring

27.6.1 In the event that, pursuant to any provincial, federal legislation or corporate reorganization, the current corporate structure or the function of MECL as a vertically integrated utility is dissolved or restructured or changed in such a manner that MECL, or any successor entity, does not have the power and authority, statutory or otherwise to perform the obligations set forth in this Agreement (a "Restructuring"), this Agreement shall terminate coincident with the effective date of the Restructuring, provided MECL, upon Restructuring, uses all reasonable efforts, in good faith, to first secure the necessary power and authority, statutory or otherwise, to perform its obligations set forth in this Agreement, but is unable, due to circumstances beyond its control, to secure such power and authority.

27.6.2 If a Restructuring occurs and the provisions of the legislation authorizing the Restructuring, or the provisions of any legislation, provide that the entity which is given, or undertakes, or assumes, in the Restructuring, the obligations of entering into energy purchase agreements shall be bound by the terms of this Agreement, this Agreement shall not terminate and such entity shall be bound by the terms of this Agreement from and after the date of the Restructuring to the same extent and in the manner as if it had been an original party to this Agreement in the place and stead of the original MECL.

27.7 Waiver

No delay or omission by the Parties in exercising any right or remedy provided for herein shall constitute a waiver of such right or remedy nor shall it be construed as a bar to or waiver of any such right or remedy on any future occasion.

27.8 Right of Waiver

Each Party, in its sole discretion, shall have the right, but shall have no obligation, to waive, defer or reduce any of the requirements to which any other Party is subject under this Agreement at any time; provided, however, that no Party shall be deemed to have waived, deferred or reduced any such requirements unless such action is in writing and signed by the waiving party. A Party's exercise of any rights hereunder shall apply only to such requirements and on such occasions as such Party may specify and shall in no event relieve the other Party of any requirements or other obligations not so specified.

27.9 Amendments

This Agreement may be modified or amended only by an instrument in writing signed by the Parties.

27.10 Counterparts

This Agreement may be executed by the Parties in one or more counterparts, all of which taken together, shall constitute one and the same instrument. The facsimile signatures of the Parties shall be deemed to constitute original signatures, and facsimile copies hereof shall be deemed to constitute duplicate originals.

27.11 Severability

The invalidity of one or more phrases, sentences, clauses, sections or articles contained in this Agreement shall not affect the validity of the remaining portions of this Agreement so long as the material purposes of this Agreement can be determined and effectuated.

27.12 Joint Effort

Preparation of this Agreement has been a joint effort of the Parties and the resulting document shall not be construed more severely against one of the Parties than against the other. Any rule of construction that ambiguities are to be resolved against the drafting party shall not be employed in the interpretation of this Agreement, or any amendments or exhibits hereto.

27.13 Recitals

The Recitals form part of this Agreement and shall have effect as if set out in full in the body of the Agreement and accordingly any reference to this Agreement includes the Recitals.

27.14 Effectiveness

This Agreement shall be effective on, and shall be binding upon, the Parties upon the full execution and delivery of this Agreement, as of the Effective Date.

27.15 Further Assurances

The Parties agree that each of them shall, upon reasonable request of the other, do or cause to be done all further lawful acts, deeds and assurances whatever for the better performance of the terms and conditions of this Agreement.

27.16 Survival

The provisions of this Agreement which, by their terms, are intended to survive or which must survive in order to give effect to continuing obligations of the Parties, shall survive the termination or expiry of this Agreement.

27.17 Time

Time is of the essence of this Agreement and all the provisions thereof.

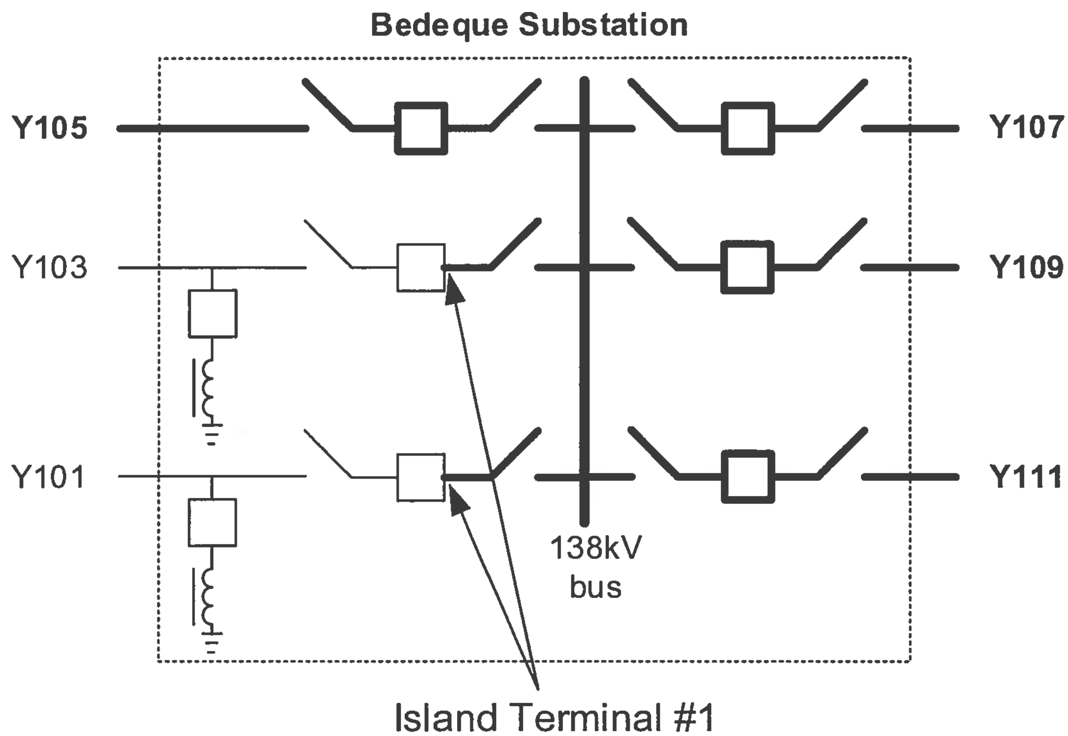
[THE REMAINDER OF THIS PAGE LEFT INTENTIONALLY BLANK]

IN WITNESS WHEREOF the Parties have executed this Agreement on the day and year first above written.

	)	**Government of Prince Edward Island**
Witness	)	Per: Hon. Paula Biggar, Minister of Transportation, Infrastructure and Energy
	)	**Prince Edward Island Energy Corporation**
Witness	)	Per: Kim Horrelt, Chief Executive Officer
	)	**Maritime Electric Company, Limited**
Witness	)	Per: John Gaudet, President and Chief Executive Officer

Appendix "A"

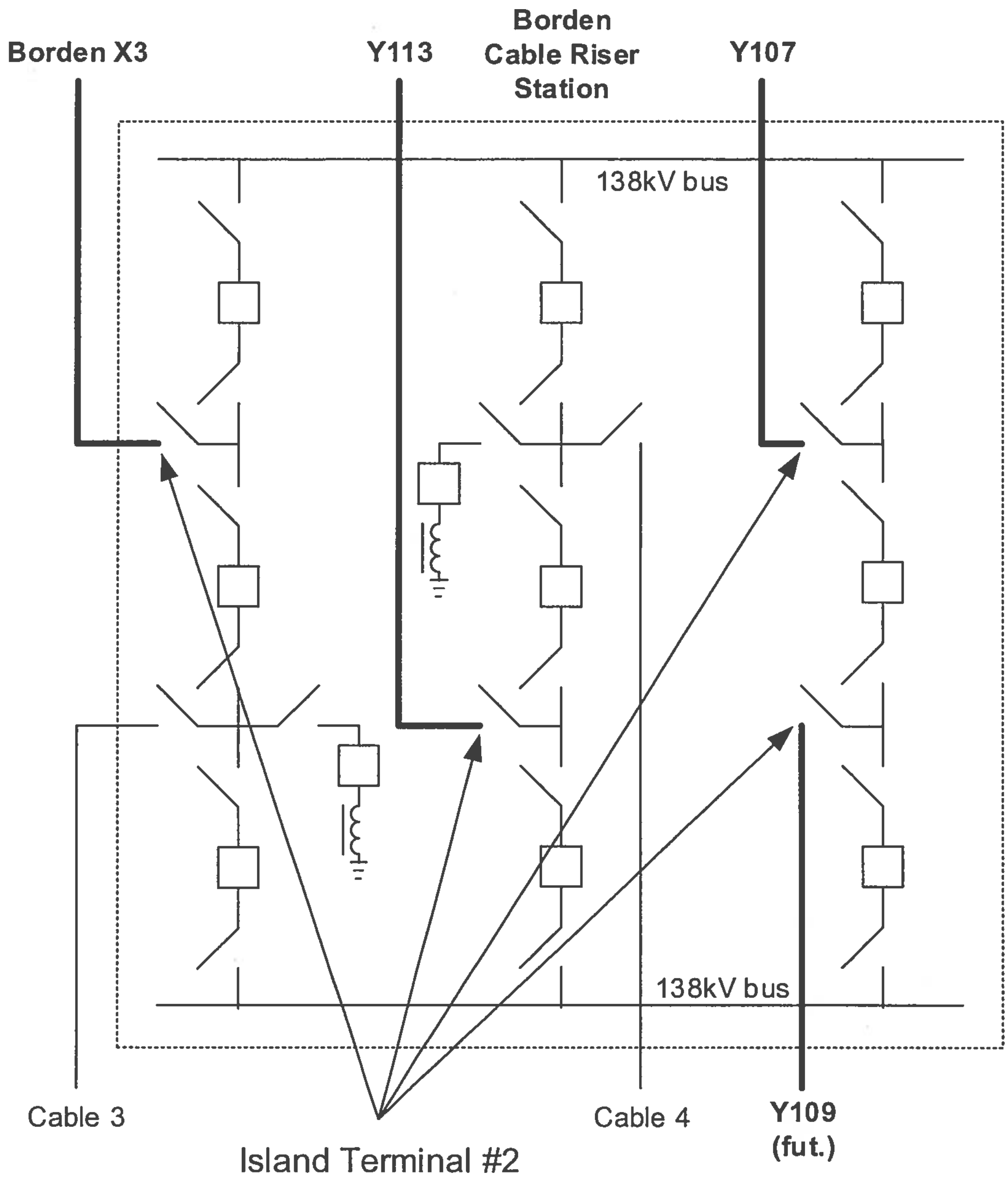
Island Terminal #1



MECL-owned facilities illustrated in BOLD LINE
Owner-owned facilities illustrated in THIN LINE

Appendix "B"

Island Terminal #2



MECL-owned facilities illustrated in BOLD LINE
Owner-owned facilities illustrated in THIN LINE

STEWART MCKELVEY
LAWYERS • AVOCATS

65 Grafton Street, P.O. Box 2140
Charlottetown PE C1A 8B9 Canada tel: 902.892.2485 fax: 902.566.5283
stewartmckelvey.com

October 10, 2017

D. Spencer Campbell, Q.C.
Direct Dial: 902.629.4549
Direct Fax: 902.566.5283
scampbell@stewartmckelvey.com

PERSONAL & CONFIDENTIAL

Mr. Jason C. Roberts
Vice President, Finance & Chief Financial Officer
Maritime Electric Company, Limited
180 Kent Street, P.O. Box 1328
Charlottetown PE C1A 7N2

RECEIVED
OCT 10 2017

Dear Mr. Roberts:

Re: PEI – NB Interconnection Facilities
Our File No.: SM5093.111

Please find enclosed correspondence and enclosures from J. Gordon MacKay, Q.C., which is self-explanatory.

Should you have any questions or concerns, please do not hesitate to contact me.

Yours truly,

STEWART MCKELVEY

D. Spencer Campbell

DSC/mcd

Enclosures

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CSM CARR, STEVENSON, & MACKAY
BARRISTERS AND SOLICITORS

65 Queen Street
P.O. Box 522
Charlottetown
Prince Edward Island
C1A 7L1

Telephone: (902) 892-4156
Facsimile: (902) 566-1377
Web: www.csmlaw.com

RECEIVED
OCT 0 6 2017

October 5, 2017

DELIVERED

D. Spencer Campbell, Q.C.
Stewart McKelvey
65 Grafton Street
Charlottetown, PE

Dear Mr. Campbell:

Re: PEI-NB Interconnection Facilities

For your records and the records of your client Maritime Electric Company, Limited I enclose one fully executed original of each of the following documents:

1. The Interconnection Lease Agreement between the Province of Prince Edward Island, The Prince Edward Island Energy Corporation, and Maritime Electric Company, Limited effective as at July 1, 2017;

2. The Debt Collection Agreement between the Province of Prince Edward Island, The Prince Edward Island Energy Corporation, The City of Summerside, and Maritime Electric Company, Limited dated effective July 1, 2017.

Yours very truly,

CARR STEVENSON & MacKAY

J. GORDON MacKAY, Q.C.
JGM/id
Enc.

PEI-NB INTERCONNECTION FACILITIES

DEBT COLLECTION AGREEMENT

BETWEEN

THE PROVINCE OF PRINCE EDWARD ISLAND

AND

THE PRINCE EDWARD ISLAND ENERGY CORPORATION

AND

MARITIME ELECTRIC COMPANY, LIMITED

AND

CITY OF SUMMERSIDE

JULY 2017

DEBT COLLECTION AGREEMENT

THIS AGREEMENT made as at the 1st day of July 2017 (the "Effective Date"),

BETWEEN:

THE GOVERNMENT OF PRINCE EDWARD ISLAND, as represented by the Minister of Transportation, Infrastructure and Energy (hereinafter referred to as the "**Province**")

OF THE FIRST PART

- AND -

THE PRINCE EDWARD ISLAND ENERGY CORPORATION, a body corporate, established pursuant to section 2 of the *Energy Corporation Act*, R.S.P.E.I. 1988, Cap. E-7, as represented by its Chief Executive Officer (hereinafter referred to as the "**Energy Corporation**")

OF THE SECOND PART

- AND -

MARITIME ELECTRIC COMPANY, LIMITED, a body corporate, incorporated under the Canada Business Corporations Act, R.S.C 1985, c. C-44, as represented by its President and Chief Executive Officer (hereinafter referred to as "**MECL**")

OF THE THIRD PART

-AND-

CITY OF SUMMERSIDE, a body corporate, duly incorporated under the laws of the Province of Prince Edward Island, as represented by its Mayor,
(hereinafter referred to as "**Summerside**")

OF THE FOURTH PART.

WHEREAS the Province owns a nominal 200-MW interconnection from Island Terminal #1 to Mainland Terminal #1 (hereinafter referred to as Interconnection #1);

AND WHEREAS the Energy Corporation owns a nominal 360-MW interconnection from Island Terminal #2 to Mainland Terminal #2 (hereinafter referred to as Interconnection #2);

AND WHEREAS MECL is a public utility as defined in the *Electric Power Act,* R.S.P.E.I 1988, Cap. E-4 (the "Act") with a franchise to produce, transmit, distribute and furnish electric energy in Prince Edward Island;

AND WHEREAS Summerside owns and operates a utility for the production and supply of electric power and energy to its customers in and around the City of Summerside;

AND WHEREAS the Parties wish to cooperate such that the Interconnection Facilities are operated and maintained in accordance with Good Utility Practice for the benefit of the electric power consumers of the Province of Prince Edward Island and other transmission users as the case may be;

AND WHEREAS the Province and the Energy Corporation have leased the Interconnection Facilities to MECL;

AND WHEREAS MECL and the Owners have, under said Lease, agreed that MECL shall operate and maintain the Interconnection Facilities and that the cost of doing so shall be recoverable through the Open Access Transmission Tariff implemented by MECL and approved by the Prince Edward Island Regulatory and Appeals Commission under the provisions of the *Electric Power Act* RSPEI 1988, Cap. E-4;

AND WHEREAS the Energy Corporation has financed the cost of the construction and commissioning of Interconnection #2 and associated parts of the NB Interconnection Transmission;

AND WHEREAS the Energy Corporation intends to recover its entire investment in Interconnection #2 and associated parts of the NB Interconnection Transmission including all interest expense from the customers of MECL and Summerside;

AND WHEREAS the intention is that MECL and Summerside shall make no profit and suffer no loss in relation to the construction of Interconnection #2 and associated parts of the NB Interconnection Transmission, and/or the recovery of the Energy Corporation's entire investment from customers;

AND WHEREAS the amount of the Debt at the date of the execution of this Agreement and the expected Interest Rates available to the Energy Corporation to finance the Debt are set out in Schedule "A" attached to this Agreement;

AND WHEREAS pursuant to the terms of this Agreement, the Debt is to be collected by MECL and Summerside from their respective customers as part of their lawful rates, tolls and charges, on behalf of the Energy Corporation and remitted to the Energy Corporation as required by the terms of this Agreement;

AND WHEREAS the Debt is collected by MECL and Summerside as agent for the Energy Corporation;

Now Therefore this Agreement Witnesseth that, in consideration of the premises, mutual covenants and agreements contained herein, and subject to the terms and conditions of this Agreement, the Parties agree as follows:

Article 1 – Definitions

1.1 The terms defined in this Article 1.1 shall have, for all purposes of this Agreement, the following meanings:

(i) **"Agreement"** means this instrument governing the collection of Debt incurred by the Energy Corporation in respect of Interconnection #2 and associated parts of the NB Interconnection Transmission as may be amended from time to time, and the expressions, "herein", "hereto", "hereof", "hereby", "hereunder" and similar expressions referred to in this instrument shall refer to the instrument hereto as so defined and not to any particular article, section, subsection or other subdivision hereof;

(ii) **"Applicable Laws"** means all laws, statutes, bylaws, rules, directives, policies, codes, regulations, treaties, requirements, standards, orders and decrees of, or issued by, any Authority, as may be amended from time to time, that are applicable to, and that are legally binding on or in respect of, the Parties and this Agreement, and any matter or thing related to or in respect of any of them, or any other matter or thing arising under or in respect of this Agreement, including under the common law and equity, to the extent applicable;

(iii) **"Authority"** means each and every government, governmental agency, authority, bureau or department, court, or other entity or instrumentality, as practicable, having legal jurisdiction;

(iv) **"Business Day"** shall mean any day other than a day on which banking institutions in the Province of Prince Edward Island are authorized to close;

(v) **"Capital Addition"** means any addition of facilities which consists of one or more Units of Property made after consultation between the Owners, MECL, and Summerside through the Interconnection Committee, following the In-Service Date as may be necessary to retain and/or to increase the capacity of the Interconnection Facilities;

(vi) **"Capital Replacement"** means any addition of facilities which is made to take the place of any part of the Interconnection Facilities removed from service and which consists of one or more Units of Property made after consultation between the Owners and MECL, and Summerside will be advised through the Interconnection Committee of such actions;

(vii) **"Commission"** means the Prince Edward Island Regulatory and Appeals Commission as established under the *Island Regulatory and Appeals Commission Act,* R.S.P.E.I. 1988, Cap. I-11;

(viii) **"Council"** means the Council of the City of Summerside;

(ix) **"Debt"** shall have the meaning ascribed in Article 2;

(x) **"Debt Collection Rates"** shall have the meaning ascribed in Article 3;

(xi) **"External Arbitration Procedures"** shall have the meaning ascribed in Section 12.2;

(xii) **"Good Utility Practice"** means those project management, design, procurement, construction, operation, maintenance, repair, removal, and disposal practices, methods and acts that are engaged in by a significant portion of the electric utility industry in Canada during the relevant time period, or any other practices, methods or acts that, in the exercise of reasonable judgment in light of the facts known at the time a decision is made, could have been expected to accomplish a desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be the optimum practice, method, or act to the exclusion of others, but rather to be a spectrum of acceptable practices, methods or acts generally accepted in such electric utility industry for the project management, design, procurement, construction, operation, maintenance, repair, removal and disposal of electric utility facilities in Canada. Notwithstanding the foregoing references to the electric utility industry in Canada, in respect solely of Good Utility Practice regarding subsea alternating current transmission cables, the standards referenced shall be the internationally recognized standards for such practices, methods, and acts generally accepted with respect to subsea alternating current transmission cables. Good Utility Practice shall not be determined after the fact in light of the results achieved by the practices, methods or acts undertaken but rather shall be determined based upon the consistency of the practices, methods or acts when undertaken with the standard set forth in the first two sentences of this definition at such time;

(xiii) **"Initial Capital Cost"** means, for purposes of this Agreement, the aggregate of all the costs of construction and commissioning of Interconnection #2 and associated parts of the NB Interconnection Transmission incurred by the Energy Corporation, net of funding received from the Government of Canada, up to the In-Service Date, including interest actually paid by the Energy Corporation from the time planning for construction began until the In-Service Date, plus any costs incurred for the construction and commissioning of Interconnection #2 and associated parts of the NB Interconnection Transmission incurred by the Energy Corporation after signing of this Agreement;

(xiv) **"In-Service Date"** means July 1, 2017;

(xv) **"Interconnection Abandonment"** means the abandonment of the Interconnection Facilities, where, as a result of submarine cables or other facilities being degraded, destroyed or damaged to an extent rendering repairs impractical or uneconomic, or being otherwise involuntarily removed from the possession and control of the Owners and MECL, the Owners and MECL mutually agree not to replace them;

(xvi) **"Interconnection #1"** means all facilities, equipment, apparatus, transmission lines and structures of every kind and nature required for and used in connection with the transmission of electric power and energy from Mainland Terminal #1 to Island Terminal #1 and existing at the In-Service Date, including but not limited to:

(a) Two, three conductor, 138 kV submarine cables having an approximate capacity of 200 MW, cable termination stations on New Brunswick and on Prince Edward Island to change the mode of transmission from submarine cable to overhead conductor and to permit switching of cable circuits and 138 kV overhead transmission lines from such stations to Mainland Terminal #1 and Island Terminal #1 respectively;
(b) Transmission, switching, control and metering facilities and compensation devices which may be required to transmit power from Mainland Terminal #1 to Island Terminal #1 and vice versa; and
(c) All facilities, equipment, apparatus, structures and land required for the operation of all such facilities, including electric signs, markers and other necessary warnings to navigation and located between Mainland Terminal #1 and Island Terminal #1;

(xvii) **"Interconnection #2"** means all facilities, equipment, apparatus, transmission lines and structures of every kind and nature required for and used in connection with the transmission of electric power and energy from Mainland Terminal #2 to Island Terminal #2 and existing at the In-Service Date including but not limited to:

(a) Two, three conductor, 138 kV submarine cable systems having an approximate capacity of 360 MW, cable termination stations in New Brunswick and on Prince Edward Island to change the mode of transmission from submarine cable to overhead conductor and to permit switching of cable circuits and 138 kV overhead transmission lines from such stations to Mainland Terminal #2 and Island Terminal #2 respectively;
(b) Transmission, switching, control and metering facilities and compensation devices which may be required to transmit power from Mainland Terminal #2 to Island Terminal #2 and vice versa; and

(c) All facilities, equipment, apparatus, structures and land required for the operation of all such facilities, including electric signs, markers and other necessary warnings to navigation and located between Mainland Terminal #2 and Island Terminal #2;

(xviii) **"Interconnection Committee"** means the committee constituted under Article 9;

(xix) **"Interconnection Facilities"** means Interconnection #1, Interconnection #2 and NB Interconnection Transmission or parts thereof;

(xx) **"Interest"** means, in respect of its application to Interconnection #2 and associated parts of the NB Interconnection Transmission, and for the purposes of this Agreement and the Schedules thereto, the financing costs incurred by the Energy Corporation based on the Interest Rates charged to the Energy Corporation as set out in Schedule "A" which may change from time to time, net of any amounts earned on the Sinking Fund;

(xxi) **"Interest Rate"** means the lowest annualized borrowing cost available to the Energy Corporation to finance the Debt and does not include any administrative or guarantee fees;

(xxii) **"Island Terminal #1"** means the point at which the Interconnection Facilities transition to transmission facilities owned by MECL in Bedeque, PEI;

(xxiii) **"Island Terminal #2"** means the point at which the Interconnection Facilities transition to transmission facilities owned by MECL in Borden-Carleton, PEI;

(xxiv) **"Mainland Terminal #1"** means the point at which the cable system transitions to transmission facilities owned by NB Power in Murray Corner, NB;

(xxv) **"Mainland Terminal #2"** means the point at which the cable system transitions to transmission facilities owned by NB Power in Cape Tormentine, NB;

(xxvi) **"Memramcook Terminal "** means the point at which the NB Interconnection Transmission transitions in Memramcook, NB, to the balance of the NB Power transmission system;

(xxvii) **"NB"** means the Province of New Brunswick;

(xxviii)**"NB Interconnection Transmission"** means the transmission facilities in New Brunswick that are owned by NB Power and are designated as direct assignment facilities in accordance with the NB Power Open Access Transmission Tariff and by agreement between NB Power, MECL and the Owners;

(xxix) **"NB Power"** means the New Brunswick Power Corporation.

(xxx) **"OATT"** means MECL's Open Access Transmission Tariff as approved by the Commission under Section 20 of the *Electric Power Act*, R.S.P.E.I. 1988, Cap. E-4, or a successor transmission system access tariff as the case may be;

(xxxi) "**Operation and Maintenance License Agreement**" means an agreement entered into between Her Majesty The Queen in Right of Canada, Her Majesty The Queen in Right of Prince Edward Island, Her Majesty The Queen in Right of New Brunswick and The Prince Edward Island Energy Corporation and Maritime Electric Company, Limited, and entitled "Operations and Maintenance License Agreement for PEI-NB Cable Interconnection Upgrade Project";

(xxxii) **"Owner" or "Owners"** means the Province and the Energy Corporation, jointly or severally;

(xxxiii)"**Party**" means either the Province, Energy Corporation, Summerside or MECL and "**Parties**" refers to all of the Province, Energy Corporation, Summerside and MECL;

(xxxiv)**"PEI"** means the Province of Prince Edward Island;

(xxxv) **"Rate Base"** means the maximum valuation of assets fixed by the Commission pursuant to the *Electric Power Act*, RSPEI 1988, Cap E-4 upon which MECL may earn a percentage of return established by the Commission or another method of computing the maximum return as determined by the Commission;

(xxxvi)"**Rate of Return**" means the earnings received by the Energy Corporation on the Sinking Fund, expressed as a percentage;

(xxxvii) "**Sinking Fund**" means the monies set aside by the Energy Corporation to provide for a lump sum payment on the principal balance of the Debt outstanding at March 1, 2046;

(xxxviii) "**Subsequent MECL Capital Costs**" means the aggregate cost of Capital Replacements and/or Capital Additions incurred by MECL after the In-Service Date including interest during construction which are paid for by MECL;

(xxxix)"**Transmission Users**" means a 'Transmission Customer' as defined in the OATT who takes 'Transmission Service' as defined in the OATT;

(xl) "**Unit of Property**" means the smallest item of property which is separately written into the Interconnection Facilities plant account.

Article 2 – Debt

2.1 The Debt incurred by the Energy Corporation in respect of the Initial Capital Cost of Interconnection #2 and associated parts of the NB Interconnection Transmission is as set out in Schedule "A".

2.2 Pursuant to the terms of this Agreement, the Debt, including all interest charges, is to be collected by MECL and Summerside from their respective customers as part of their lawful rates, tolls and charges, on behalf of the Energy Corporation and remitted to the Energy Corporation as required by the terms of this Agreement.

Article 3 – Debt Collection Rates

3.1 The Debt to be collected on behalf of the Energy Corporation by MECL and Summerside in relation to the Initial Capital Cost of Interconnection #2 and associated parts of the NB Interconnection Transmission shall be collected at amounts of $268,128.14 and $30,123.41, plus HST, respectively, per month from March 1, 2017 until the end of the first five years of this Agreement.

3.2 At the end of the first five year period and each subsequent five year period, the Debt Collection Rates will be adjusted to take into account:

i. the contribution ratio determined in accordance with Article 8 of this Agreement;

ii. the Interest Rate available to the Energy Corporation at that time; and

iii. any shortfall in collections resulting from a change in the Interest Rate available to the Energy Corporation or any other input that occurred during the five year period and for which no Debt Collection Rate Adjustment pursuant to Article 6 occurred.

3.3 The Debt Collection Rates as set out in Section 3.1 include $30,000 to be deposited in the Sinking Fund on a monthly basis by the Energy Corporation, and shall be collected from MECL and Summerside at a rate of $26,970 and $3,030, respectively, per month from March 1, 2017 until the end of the first five years of this Agreement.

3.4 Any amounts collected in excess of the amount required to make the Energy Corporation's loan payments will be deposited in the Sinking Fund.

Article 4 – Collection Procedure

4.1 The Debt to be collected on behalf of the Energy Corporation by MECL and Summerside as set out herein shall be collected each month by MECL and Summerside as agents for the Energy Corporation and remitted to the Energy Corporation by the 7th Business Day of the following month.

4.2 All amounts collected by MECL and Summerside from March 1, 2017 to the end of the month in which this Agreement is executed shall be remitted to the Energy Corporation by the 7th Business Day of the month following the execution of this Agreement.

Article 5 – Term of Agreement

5.1 The term of this Agreement shall be to February 28, 2056, or until such time as the Debt has been collected in full by MECL and Summerside on behalf of the Energy Corporation, whichever is earlier. This Agreement shall commence on the In-Service Date (the "Term").

Article 6 - Debt Collection Rate Adjustments

6.1 The Parties agree that the Debt Collection Rates established by this Agreement are intended to provide the Energy Corporation with full recovery of the Debt and associated financing charges as set out herein, and collected by MECL and Summerside on behalf of the Energy Corporation from their customers within the Term of this Agreement. The Parties further agree that the intention is that MECL and Summerside shall act as agents for the Energy Corporation in the collection of all amounts legally required by this Agreement and shall make no profit and suffer no loss in their capacity as agents.

6.2 The calculation of the Debt Collection Rates in this Agreement, and any determination of any material change with respect to Interest Rates, does not include any administrative or guarantee fees.

6.3 The parties agree that the Debt Collection Rates established by this Agreement are based upon the fixed Interest Rate obtained by the Energy Corporation for the credit facility as set out in Schedule "A".

6.4 Notwithstanding any other provision of this Agreement, in the event there is a material change in the Interest Rate available to the Energy Corporation for credit facilities as set out in Schedule "A" or any of the other assumptions or inputs contained in this Agreement which would result in the amount collected being insufficient to fund the repayment of the Debt by February 28, 2056, the Energy Corporation shall have the option to require that MECL and Summerside adjust the monthly Debt Collection Rates set out in this Agreement to reflect the current Interest Rate available. No adjustment to the Debt Collection Rates pursuant to this section shall be made prior to March 1, 2019.

6.5 Any dispute with respect to the current Interest Rate available to the Energy Corporation or the existence of a material change in Interest Rate available to the Energy Corporation shall be resolved in accordance with Article 12.

Article 7 – Additional Funding Received in Relation to the Debt

7.1 The parties agree that any funding recovered or received by the Energy Corporation from the Government of Canada in relation to Interconnection #2 and associated parts of the

NB Interconnection Transmission after the In-Service Date shall be applied directly to the principal balance of the Debt outstanding at the time the Energy Corporation recovers or receives the funding. For greater certainty, the parties agree that a substantial funding recovery or receipt by the Energy Corporation pursuant to this section may result in a material change in the inputs for the purpose of Section 6.4 of this Agreement.

Article 8 – Contribution Ratio and Rights to Interconnection Capacity

8.1 Interconnection #1 and Interconnection #2 are part of the MECL Transmission System.

8.2 MECL and Summerside are contributing to the Initial Capital Cost of Interconnection #2 and associated parts of the NB Interconnection Transmission in accordance with this Agreement.

8.3 The Summerside percentage of the average 12 month coincident peak demand for electricity during the five year period preceding the execution of this agreement is calculated to be 10.1% as set out in Schedule "B".

8.4 The MECL percentage of the average 12 month coincident peak demand for electricity during the five year period preceding the execution of this agreement is calculated to be 89.9% as set out in Schedule "B".

8.5 The contribution ratio for each of MECL and Summerside is based on a five year average of each of MECL's and Summerside's percentage of the average 12 month coincident peak demand of electrical consumption in PEI as agreed upon by MECL and Summerside.

8.6 The contribution ratio for each of MECL and Summerside shall be fixed for each five year period as per Section 3.2. At the end of each five year period, the contribution ratio shall be recalculated based on the average of the each of MECL's and Summerside's relative share of the average 12 month coincident peak demand of electrical consumption in PEI for the immediately preceding five year period.

8.7 The Parties hereto agree that each of MECL and Summerside shall have assured access to the same percentage of the available import capacity from NB to PEI over the Interconnection Facilities as they are contributing payments at that time towards the Debt, as set out in Schedule "B".

8.8. For greater certainty, each of MECL's and Summerside's relative share of contributions towards recovery of the Debt as per Article 3 shall be the same as their respective relative share of entitlement of available import capacity from NB to PEI over the Interconnection Facilities.

8.9 The Parties hereto agree that during the first five years of this agreement that Summerside shall have assured access to 10.1% of the import capacity from NB to PEI of the Interconnection Facilities.

8.10 The Parties hereto agree that during the first five years of this agreement that MECL shall have assured access to 89.9% of the import capacity from NB to PEI of the Interconnection Facilities.

Article 9 – Interconnection Committee

9.1 A committee to be known as the Interconnection Committee shall be established within 30 days of the Effective Date, consisting of one representative from each of the Province, Energy Corporation, MECL, and Summerside for the following purposes:

i) the Interconnection Committee will meet on a semi-annual basis to review the operation, maintenance and cost report prepared by MECL and to receive updates on the condition of the assets and inspection reports.

ii) the Interconnection Committee will provide oversight as to the operation and maintenance of the Interconnection Facilities and in particular, contemplated Capital Additions or Capital Replacements, it being recognized that the Interconnection Committee exists principally for the sharing of information regarding the Interconnection Facilities, and also recognizing that ultimate control over the Interconnection Facilities vests in the Owners as per the terms of this Agreement.

9.2 The Interconnection Committee is not authorized to modify or amend any terms of this Agreement. While members of the Interconnection Committee may incur expenses that result from the Interconnection Committee's activities in accordance with this Agreement, the Interconnection Committee has no authority to commit or otherwise contractually bind any of the members of the Committee to directly incur or pay any cost or expenditure.

9.3 Energy Corporation shall prepare the agenda for the meetings which shall include matters specified by any of the representatives on the Interconnection Committee. The agenda shall be settled and circulated fourteen days prior to the semi-annual meetings. Special meetings of the Interconnection Committee may be called at any time by the Energy Corporation representative on the Committee or at the request of two or more of the other Committee members.

9.4 Matters to be included in the agenda for discussion at a meeting of the Interconnection Committee shall include but not be limited to the following:

a) amending, adding, or cancelling schedules;

b) assessment of compliance with the terms of this Agreement;

c) preparation, documentation, retention and distribution of Interconnection

Committee minutes and agendas as prepared by or on behalf of the Energy Corporation; and

d) discussion for the purpose of input into the development and implementation of decisions involving but not limited to the following work activities:
   (i) development and maintenance of procedures for active power and reactive power accounting, including but not limited to methods of energy balancing;
   (ii) approval of information and data exchange costs and scope;
   (iii) documented points of operational data, as required by mutual agreement;
   (iv) development and maintenance of outage scheduling and coordination procedures with respect to the reliable operation of the Interconnection Facilities;
   (v) coordination of system tests;
   (vi) development of system restoration and mutual assistance procedures; and
   (vii) approval of required Capital Additions and Capital Replacements, Interconnection Abandonment, and Operation and Maintenance License Agreement.

Article 10 - Ownership

10.1 Nothing in this Agreement is intended to create, or shall create, in favour of MECL or Summerside, their successors and assigns, any legal title of any nature whatsoever in the property comprising the Interconnection Facilities.

10.2 Nothing contained herein shall be construed as creating a partnership, joint venture or association of any kind.

10.3 The Parties agree that entry into this Agreement will not result in the appointment or employment of MECL or Summerside, or any officer, clerk, employee or agent of MECL or Summerside, as an officer, clerk, employee or agent of the Province or the Energy Corporation, nor shall the *Civil Service Act*, R.S.P.E.I. 1988, Cap. C-8 apply.

10.4 Nothing contained herein shall be construed as providing any rights to MECL or Summerside with respect to the use of fibre optic cables that form part of Interconnection #2 except to the extent necessary for the operation and monitoring of the Interconnection Facilities.

Article 11 - Regulation

11.1 MECL's participation in this Agreement shall be subject to the approval of the Commission.

11.2 The Parties agree that this Agreement is subject at all times to review and revision by the Commission provided, however, that should any review or revision made by the

Commission be material, a Party may invoke the dispute resolution procedures contained in Article 12 of this Agreement. Further, in the event that any review or revision by the Commission would result in MECL making a profit or suffering a loss in relation to the construction of Interconnection #2 and associated parts of the NB Interconnection Transmission, this Agreement may be terminated by either the Energy Corporation or MECL.

11.3 In the process of the regulation of the electric power and energy rates of MECL by the Commission, no part of the Initial Capital Cost, or Capital Addition and/or Capital Replacement costs that are paid for by the Owners, shall be included in the Rate Base as submitted from time to time by MECL for the approval of the Commission.

11.4 Any Subsequent MECL Capital Costs that are otherwise not collected from the Owners may be included in the Rate Base and collected from Transmission Users in accordance with the provisions of the OATT as submitted from time to time by MECL for approval by the Commission.

11.5 MECL shall not claim depreciation of any part of the Initial Capital Cost, or Capital Addition and/or Capital Replacement costs that are paid for by the Owners, as an operating expense.

Article 12 - Dispute Resolution

12.1 Internal Dispute Resolution Procedures

Any dispute between the Owners and MECL or Summerside as to their rights under this Agreement shall be referred to a designated senior representative of the Owners and a senior representative of MECL or a senior representative of Summerside as the case may be for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) business days (or such other period as the Parties may agree upon) by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures

Any arbitration initiated under this Agreement shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) business days of the referral of the dispute to arbitration, each party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) business days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any Party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the *Arbitration Act*, R.S.P.E.I. 1988, Cap. A-6 and any applicable Commission rules or regulations.

12.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Agreement and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction.

12.4 Costs

Each party to an arbitration shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(i) The cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(ii) Its' proportionate share of the cost of the single arbitrator jointly chosen by the Parties.

In the event that it is necessary to enforce such award, all costs of enforcement shall be payable and paid by the Party against whom such award is enforced.

12.5 Referral of Dispute to the Commission

Notwithstanding anything contained in this Article 12, any Party may, instead of proceeding through the External Arbitration Procedures outlined in Section 12.2 above, request the Commission hear and decide the dispute by filing a complaint with the Commission pursuant to the *Electric Power Act*, R.S.P.E.I. 1988, Cap. E-4, in the manner set out below and the decision of the Commission with respect to the matter shall be final and binding and the matter in dispute cannot thereafter proceed to the dispute resolution process. Complaints filed with the Commission must be in writing and must include reasons and evidence in support of the dissatisfied Party's position. A copy of the complaint, together with the supporting reasons and evidence, must be filed with the other Party or Parties.

The Commission may require a complainant to provide such security for the costs incurred or to be incurred by the Commission, as it considers reasonable, and such security may be forfeited to the Commission if the complaint is not substantiated.

12.6 Enforcement of Arbitration Decision

The *Arbitration Act*, R.S.P.E.I. 1988, Cap. A-6 shall govern the procedures to apply in the enforcement of any award made pursuant to Section 12.3.

Article 13 - Representations and Warranties of the Owners

13.1 The Province and the Energy Corporation represent and warrant to MECL and Summerside that: (i) the Energy Corporation is a body corporate, validly existing, and in good standing under the laws of PEI; (ii) the Owners have all necessary corporate power, authority and capacity to enter into this Agreement and to carry out their obligations under this Agreement and that the execution, delivery and performance of this Agreement have been duly authorized by all necessary corporate or administrative action of the Owners; (iii) there is no claim, action, proceeding or other litigation pending or, to the knowledge of the Owners threatened, which, if adversely determined, would restrict or otherwise interfere in any material respect with the obligations of the Owners under this Agreement; (iv) this Agreement constitutes a legal, valid and binding obligation of the Owners enforceable against the Owners in accordance with its terms, subject as to enforcement limits imposed by bankruptcy, insolvency or similar laws affecting creditors' rights generally and the availability of equitable remedies.

13.2 The execution and delivery of this Agreement by the Owners and the performance of these obligations contained herein will not result in the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the acceleration of any obligation of the Owners under: (i) any contract, agreement, instrument or other document to which the Province or the Energy Corporation is a party or by which it or its properties or assets are bound; (ii) the constating documents of the Energy Corporation; (iii) any judgment, decree, order or award of any government agency having jurisdiction over the Province or the PEI Energy Corporation; (iv) any license, permit, approval, consent or authorization held by or for the benefit of the Province or the Energy Corporation; or (v) any Applicable Laws, statute, ordinance, regulation or rule.

Article 14 - Representations and Warranties of MECL

14.1 MECL represents and warrants to the Owners that: (i) MECL is a body corporate and is validly existing and in good standing under the laws of Canada; (ii) MECL has all necessary power, authority and capacity to enter into this Agreement and to carry out its obligations under the Agreement and that the execution, delivery and performance of this Agreement have been duly authorized by all necessary action of MECL; (iii) there is no claim, action, proceeding or other litigation pending or, to the knowledge of MECL threatened, which, if adversely determined, would restrict or otherwise interfere in any material respect with the obligations of MECL under this Agreement; (iv) this Agreement constitutes a legal, valid and binding obligation of MECL enforceable against MECL in accordance with its terms, subject as to enforcement limits imposed by bankruptcy, insolvency or similar laws affecting creditors' rights generally and the availability of equitable remedies.

14.2 The execution and delivery of this Agreement by MECL and the performance of its obligations contained herein will not result in the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the acceleration of any obligation of MECL under: (i) any contract, agreement, instrument or other document to which MECL is a party or by which it or its properties or assets are bound; (ii) the constating documents of MECL; (iii) any judgment, decree, order or award of any government agency or tribunal having jurisdiction over MECL; (iv) any license, permit, approval, consent or authorization held by or for the benefit of MECL; or (v) any Applicable Laws, statute, ordinance, regulation or rule.

Article 15 – Representations and Warranties of Summerside

15.1 Summerside represents and warrants to the Owners that: (i) Summerside is a body corporate and is validly existing and in good standing under the laws of PEI; (ii) Summerside has all necessary power, authority and capacity to enter into this Agreement and to carry out its obligations under the Agreement and that the execution, delivery and performance of this Agreement have been duly authorized by all necessary action of Summerside; (iii) there is no claim, action, proceeding or other litigation pending or, to the knowledge of Summerside threatened, which, if adversely determined, would restrict or otherwise interfere in any material respect with the obligations of Summerside under this Agreement; (iv) this Agreement constitutes a legal, valid and binding obligation of Summerside enforceable against Summerside in accordance with its terms, subject as to enforcement limits imposed by bankruptcy, insolvency or similar laws affecting creditors' rights generally and the availability of equitable remedies.

15.2 The execution and delivery of this Agreement by Summerside and the performance of its obligations contained herein will not result in the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the acceleration of any obligation of Summerside under: (i) any contract, agreement, instrument or other document to which Summerside is a party or by which it or its properties or assets are bound; (ii) the constating documents of Summerside; (iii) any judgment, decree, order or award of any government agency or tribunal having jurisdiction over Summerside; (iv) any license, permit, approval, consent or authorization held by or for the benefit of Summerside; or (v) any Applicable Laws, statute, ordinance, regulation or rule.

Article 16 - Notice

16.1 Where in this Agreement any notice, payment, request, direction, or other communication is required to be given or made by any Party to another Party, it shall be in writing and is effective if delivered in person, sent by registered mail or by facsimile addressed to the Party for whom it is intended at the address so described in this Article and any notice, request, direction or other communication shall be deemed to have been given if by registered mail, when the postal receipt is acknowledged by the other Party; or by facsimile when transmitted.

16.1.1 The address for notice, payment, request, direction, or other communication for MECL shall be:

Maritime Electric Company, Limited
180 Kent Street
P.O. Box 1328
Charlottetown, PE C1A 7K7

Attention: Vice President, Corporate Planning & Energy Supply
Fax: 902 629-3665

16.1.2 The address for notice, payment, request, direction, or other communication for the Government of Prince Edward Island shall be:

Department of Transportation, Infrastructure and Energy
11 Kent Street, 3rd Floor
P.O. Box 2000
Charlottetown, PE C1A 7N8

Attention: Minister
Fax: 902 368-5385

16.1.3 The address for notice, payment, request, direction, or other communication for the PEI Energy Corporation shall be:

The Prince Edward Island Energy Corporation
16 Fitzroy Street
P.O. Box 2000
Charlottetown, PE C1A 7N8

Attention: Chief Executive Officer
Fax: 902 894-0290

16.1.4 The address for notice, payment, request, direction, or other communication for Summerside shall be:

City of Summerside
275 Fitzroy Street
Summerside, PE C1N 1H9

Attention: Chief Administrative Officer
Fax: 902-888-3508

16.2 The address of any Party may be changed by notice in accordance with the procedure described in Section 16.1.

Article 17 - Confidentiality and Copyright

17.1 Any and all information, knowledge or data made available to either Party by the other as a result of this Agreement shall be treated as confidential information. No Party will directly or indirectly disclose or use this information, knowledge or data or the products that arise from the information, knowledge or data for purposes unrelated to this Agreement at any time without first obtaining the written consent of the other Parties unless the information, knowledge or data is released pursuant to the Applicable Laws of Canada or by an Order of a Court of competent jurisdiction, or is generally available to the public.

17.2 The Parties agree that all lists, reports, information, statistics, compilations, analyses, and other data generated or collected in any way as a result of this Agreement are the exclusive property of the Owners and shall not be distributed, released, transmitted or used in any way, via any media, outside the purposes of this Agreement, by MECL or Summerside, its employees, agents, servants or others for whom MECL or Summerside is responsible, without the written consent of the Owners.

17.3 The Parties acknowledge that they may wish to make public announcements about the existence of certain parts of this Agreement. If MECL or Summerside is the Party advocating publicity through any medium, MECL or Summerside, as the case may be, will provide the Owners with the date and time of any proposed release of information, as well as a copy of such information proposed to be released, for review and assessment by the Owners, at least ten (10) days prior to the scheduled public release. All promotional materials and arrangements for public release related to this Agreement must be approved by the Owners prior to any public release.

Article 18 – Freedom of Information and Protection of Privacy Act

18.1 The Parties acknowledge that this Agreement, and any information pursuant to it, may be subject to release under the *Freedom of Information and Protection of Privacy Act*, R.S.P.E.I. 1988, Cap. F – 15.01, (the "Act"). MECL and Summerside shall be contacted prior to the release of information in regards to this Agreement that may be required under the Act.

18.2 MECL and Summerside acknowledges and agrees that, in the event this Agreement involves the collection or use of personal information, it is subject to the *Freedom of Information and Protection of Privacy Act*, and that personal information may not be released to any third party or unauthorized individual.

Article 19 - General

19.1 Headings

The division of this Agreement into articles and sections and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of the Agreement.

19.2 Extended Meanings

In this Agreement words importing the singular number only shall include the plural and *vice versa*, words importing the masculine gender shall include the feminine and neuter genders and *vice versa* and words importing persons shall include individuals, partnerships, associations, trusts, unincorporated organizations and corporations.

19.3 Applicable Laws

This Agreement shall be generally governed and interpreted in accordance with the laws of PEI, but is subject to Applicable Laws in the jurisdiction in which the parts of the Interconnection Facilities are located.

19.4 Survival of Agreement

This Agreement shall enure to the benefit of and be binding on the Parties and their respective successors and permitted assigns. No Party may assign or delegate its obligations under this Agreement either in whole or in part without the prior written consent of the other Parties, which consent will not be unreasonably withheld.

19.5 Audit

19.5.1 The Energy Corporation or its authorized representatives shall have the right at all reasonable times to audit, inspect, take extracts from, and make copies of records of MECL and Summerside, on a confidential basis, relating to amounts collected by MECL and Summerside in respect of Interconnection #2 and associated parts of the NB Interconnection Transmission.

19.5.2 MECL and Summerside shall provide to the Energy Corporation such facilities as required for audit and inspection and shall furnish the authorized representatives of the Energy Corporation with such information as the Energy Corporation from time to time, acting reasonably, may require with reference to the documents and information referred to in section 19.5.1.

19.5.3 MECL and Summerside shall not dispose of the documents referred to in Section 19.5.1 herein without the written consent of the Energy Corporation, but shall preserve and keep them available for audit and inspection for a period of five (5) years following the date of each document.

19.6 Restructuring

19.6.1 In the event that, pursuant to any provincial legislation, federal legislation or corporate reorganization, the current corporate structure or the function of MECL as a vertically integrated utility is dissolved or restructured or changed in such a manner that MECL, or any successor entity, does not have the power and authority, statutory or otherwise to perform the obligations set forth in this Agreement (a "Restructuring"), this Agreement shall terminate coincident with the effective date of the Restructuring, provided MECL, upon Restructuring, uses all reasonable efforts, in good faith, to first secure the necessary power and authority, statutory or otherwise, to perform its obligations set forth in this Agreement, but is unable, due to circumstances beyond its control, to secure such power and authority.

19.6.2 If a Restructuring occurs and the provisions of the legislation authorizing the Restructuring, or the provisions of any legislation, provide that the entity which is given, or undertakes, or assumes, in the Restructuring, the obligations of entering into energy purchase agreements shall be bound by the terms of this Agreement, this Agreement shall not terminate and such entity shall be bound by the terms of this Agreement from and after the date of the Restructuring to the same extent and in the manner as if it had been an original party to this Agreement in the place and stead of the original MECL.

19.7 Waiver

No delay or omission by the Parties in exercising any right or remedy provided for herein shall constitute a waiver of such right or remedy nor shall it be construed as a bar to or waiver of any such right or remedy on any future occasion.

19.8 Right of Waiver

Each Party, in its sole discretion, shall have the right, but shall have no obligation, to waive, defer or reduce any of the requirements to which any other Party is subject under this Agreement at any time; provided, however, that no Party shall be deemed to have waived, deferred or reduced any such requirements unless such action is in writing and signed by the waiving party. A Party's exercise of any rights hereunder shall apply only to such requirements and on such occasions as such Party may specify and shall in no event relieve the other Party of any requirements or other obligations not so specified.

19.9 Amendments

This Agreement may be modified or amended only by an instrument in writing signed by the Parties.

19.10 Counterparts

This Agreement may be executed by the Parties in one or more counterparts, all of which taken together, shall constitute one and the same instrument. The facsimile signatures of the Parties shall be deemed to constitute original signatures, and facsimile copies hereof shall be deemed to constitute duplicate originals.

19.11 Severability

The invalidity of one or more phrases, sentences, clauses, sections or articles contained in this Agreement shall not affect the validity of the remaining portions of this Agreement so long as the material purposes of this Agreement can be determined and effectuated.

19.12 Joint Effort

Preparation of this Agreement has been a joint effort of the Parties and the resulting document shall not be construed more severely against one of the Parties than against the other. Any rule of construction that ambiguities are to be resolved against the drafting party shall not be employed in the interpretation of this Agreement, or any amendments or exhibits hereto.

19.13 Effectiveness

This Agreement shall be effective on, and shall be binding upon, the Parties upon the full execution and delivery of this Agreement, as of the Effective Date.

19.14 Further Assurances

The Parties agree that each of them shall , upon reasonable request of the other, do or cause to be done all further lawful acts, deeds and assurances whatever for the better performance of the terms and conditions of this Agreement.

19.16 Recitals

The recitals form part of this Agreement and shall have effect as if set out in full in the body of the Agreement and accordingly any reference to this Agreement includes the Recitals.

19.15 Survival

The provisions of this Agreement which, by their terms, are intended to survive or which must survive in order to give effect to continuing obligations of the Parties, shall survive the termination or expiry of this Agreement.

19.16 Time

Time is of the essence of this Agreement and all the provisions thereof.

[THE REMAINDER OF THIS PAGE LEFT INTENTIONALLY BLANK]

IN WITNESS WHEREOF the Parties have executed this Agreement on the day and year first above written.

	)	**Government of Prince Edward Island**
Witness	)	Per: Hon. Paula Biggar, Minister of Transportation, Infrastructure and Energy
	)	**Prince Edward Island Energy Corporation**
Witness	)	Per: Kim Horrelt, Chief Executive Officer
	)	**Maritime Electric Company, Limited**
Witness	)	Per: John Gaudet, President and Chief Executive Officer
	)	**City of Summerside**
Witness	)	Per: His Worship, Mayor Bill Martin
	)	and
	)	Bob Ashley, Chief Administrative Officer

Schedule "A"

Balances, Rates and Terms

Debt / Fund	Amount Outstanding / Fund Balance as of May 31, 2017	(*Expected) Interest Rate / Rate of Return Period	Expected (*Negotiated) Interest Rates / Rate of Return Available to the Energy Corporation	Terms
Short-Term Financing	Nil (balance expected to increase to a maximum of $40,000,000)	July 1,2017 to December 31, 2017*	1.15%	Will be repaid as funding from the Government of Canada is received.
Long-Term Financing	$78,525,222	March 1, 2016 to February 28, 2046	2.512%* (may be adjusted on a periodic basis starting in 2021)	Amortized to February 28, 2056 with a balloon payment due on February 28, 2046 equal to the principal outstanding on that date. The Sinking Fund is expected to fund part of the balloon payment and the Energy Corporation intends to refinance the remaining principal balance for a period not to extend beyond February 28, 2056.
Sinking Fund	$422,302	April 6, 2016 to February 28, 2046	0.95%	A minimum of $30,000 must be deposited monthly.

Schedule "B"

Prince Edward Island Coincident Peak Loads

Sharing of Payments Based on Peaks
AVERAGE TWELVE COINCIDENT PEAK

		2012	**2013**	**2014**	**2015**	**2016**	**Average**
Summerside Peak	MW	19.6	20.6	20.8	21.5	21.4	
Maritime Electric Peak	MW	174.6	183.9	189.3	191.9	189.5	
Prince Edward Island Peak	MW	**194.2**	**204.5**	**210.1**	**213.4**	**210.9**	
Summerside Share	%	10.1	10.1	9.9	10.1	10.1	10.1
Maritime Electric Company Limited Share	%	89.9	89.9	90.1	89.9	89.9	89.9

Summary Table			
Generation		$	4,121,159
Purchases from NB			86,573,305
Purchases from Wind			23,426,491
Other Purchases			4,344,174
ECAM			(2,358,689)
Transmission			7,493,351
Distribution			4,475,584
Transmission & Distribution - Other			2,055,983
General & Administrative excluding Corporate Services and Support	5,799,733		
General & Administrative - Corporate Services & Support	2,647,973		
Total General & Administrative			8,447,706
Operating Expenses Net of ECAM - Schedule 14-4		$	138,579,065
Interest Expense			12,251,808
Amortization - Fixed Assets			21,802,450
Amortization - DSM			327,676
Amortization - Lepreau			93,400
Income Tax Expense			6,130,460
Return on Equity			13,350,423
		$	192,535,281

MARITIME ELECTRIC
A FORTIS COMPANY

June 3, 2015

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

Dear Commissioners:

Please find enclosed 10 copies of Maritime Electric's Demand Side Management and Energy Conservation Plan 2015 - 2020.

If you require further information, please do not hesitate to contact me at (902) 629-3668.

Yours truly,

MARITIME ELECTRIC

A. S. Orford
Vice President, Customer Service

ASO08
Encl. as noted

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of Section 16.1 of the Electric Power Act (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission approving an Energy Efficiency and Demand Side Management Plan for the years 2015 to 2020 and for certain approvals incidental to such an order.

APPLICATION AND EVIDENCE OF MARITIME ELECTRIC COMPANY, LIMITED

Date: June 3, 2015

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Appendix 7 Benefit cost analysis of rebate for replacing 65 Watt BR 30 incandescent reflector with 13 Watt LED BR30 reflector

Appendix 8 Benefit cost analysis of rebate for replacing 16 Watt CFL BR30 reflector with 13 Watt LED BR30 reflector

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Appendix 12 Benefit cost analysis of a Refrigerator Roundup program

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Appendix 16 Schedule of proposed yearly recovery of costs through rates

1.0 APPLICATION

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of Section 16.1 of the Electric Power Act (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission approving an Energy Efficiency and Demand Side Management Plan for the years 2015 to 2020 and for certain approvals incidental to such an order.

Introduction

1. Maritime Electric Company, Limited ("Maritime Electric" or the "Company") is a Corporation incorporated under the laws of Canada with its head or registered office at Charlottetown and carries on a business as a public utility within the scope of the Electric Power Act ("EPA" or the "Act") engaged in the production, purchase, transmission, distribution and sale of electricity within Prince Edward Island.

Application

2. Maritime Electric hereby applies for an order of the Island Regulatory and Appeals Commission ("IRAC" or the "Commission") approving the Energy Efficiency and Demand Side Management Plan ("the Plan") for the years 2015 to 2020 as outlined in the attached evidence. Maritime Electric proposes to launch the Plan in late 2015

and recover the costs of each program, in a manner similar to previous programs, through the Energy Cost Adjustment Mechanism.

3. The proposals contained in this Application represent a just and reasonable balance of the interests of Maritime Electric and those of its customers and will, if approved, allow the Company to deliver an effective Plan at a cost that is, in all circumstances, reasonable.

Procedure

4. Filed hereto is the Affidavit of Frederick J. O'Brien, Angus S. Orford and Robert O. Younker which contains the evidence in which Maritime Electric relies in this Application.

Dated this 3rd day of June, 2015.

D. Spencer Campbell
Counsel for the Applicant
Whose address for service is:

STEWART MCKELVEY
65 Grafton Street, PO Box 2140
Charlottetown PE C1A 8B9
Telephone: (902) 629-4549
Facsimile: (902) 892-2485
Email: scampbell@smss.com

2.0 AFFIDAVIT

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of Section 16.1 of the Electric Power Act (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission approving an Energy Efficiency and Demand Side Management Plan for the years 2015 to 2020 and for certain approvals incidental to such an order.

AFFIDAVIT

We, Frederick James O'Brien, of Alberton, in Prince County, and Angus Sumner Orford of Charlottetown, and Robert Owen Younker of Cornwall, in Queens County, Province of Prince Edward Island, MAKE OATH AND SAY AS FOLLOWS:

1. THAT we are respectively, the President and Chief Executive Officer and Vice President, Customer Service and Director, Corporate Planning for Maritime Electric Company, Limited ("Maritime Electric" or the "Company") and as such have personal knowledge of the matters deposed to herein, except where noted, in which

case we rely upon the information of others and in which case we verily believe such information to be true.

2. Maritime Electric is a public utility subject to the provisions of the Electric Power Act engaged in the production, purchase, transmission, distribution and sale of electricity within Prince Edward Island.

3. We prepared or supervised the preparation of the evidence and to the best of our knowledge and belief the evidence is true in substance and in fact. A copy of the evidence is attached to this our Affidavit, and is collectively known as Exhibit "A", contained in Tab 3 inclusive.

4. The evidence found at Tab 3 (the "Evidence") contains the evidence with respect to the proposed Plan.

5. The evidence found at Tab 3 (the "Appendices") contains Appendices 1 through 16 inclusive which are referred to in the evidence.

6. Tab 4 contains a proposed Order of the Commission based on the Company's Application.

SWORN SEVERALLY at
Charlottetown, County of Queens,
Province of Prince Edward Island,
The 3rd day of June, 2015.
Before me:

Fred O'Brien

Frederick J. O'Brien

Angus S. Orford

Angus S. Orford

R. O. Younker

Robert O. Younker

A Commissioner for taking Affidavits
in the Supreme Court of Prince Edward Island.

3.0 EVIDENCE

3.1 EXECUTIVE SUMMARY

This document describes Maritime Electric Company, Limited's ("Maritime Electric" or the "Company") proposed Energy Efficiency and Demand Side Management ("DSM") Plan ("the Plan") for the years 2015 to 2020.

Maritime Electric's proposed plan is summarized in the following table. It lists the measures that the Company is proposing, the reduction in energy and peak load expected to be realized through each measure, and the estimated implementation cost for each measure. The energy and peak load reductions are estimated annual values for year 5 (i.e. 2020), while the costs are the total estimated expenditures for the five year period 2016 to 2020. (Most of 2015 is expected to be taken up with obtaining approvals and subsequent planning and preparations leading up to launch of programs in late 2015.)

TABLE 1
SUMMARY OF 2015 – 2020 PROPOSED ENERGY EFFICIENCY AND DSM MEASURES

Proposed Measure	Expected annual energy saving in year five (GWh)	Expected peak load reduction in year five (MW)	Estimated cost for the five years ($ millions)	Estimated cost for after 2020 ($ millions)
$ 5.00 rebate coupon for LED light bulbs	12.2	5.9	$ 6.0	
Grants for heat pumps that operate down to -25 C in electric resistance heated homes	0.3	1.5	$ 1.0	
Incentives for thermostat shut off below -15 C of heat pumps in oil heated homes (1)	1.0	2.3	$ 3.1	$ 4.2
Customer Outreach Activities			$ 0.8	
TOTAL	**13.5**	**9.7**	**$ 10.9**	**$ 4.2**

(1) Based on a successful pilot phase in 2016 and full implementation for 2017 to 2020

The Company's proposed Plan is based on the following approach to cost effectiveness:

- Cost effectiveness is determined at the individual measure level using the California tests
- The Total Resource Cost test is the primary test of cost effectiveness
- The cost of lost space heating is taken into account

The proposed Plan is also based on the following considerations:

- It is cost effective to incent consumers to use Light Emitting Diode (LED) products. The objective is to advance the adoption of LED lighting by 10 years.

- No incentives are proposed for the purchase of compact fluorescent lighting (CFL) products. It is expected that there is limited consumer appetite for increased use of CFLs. Although CFLs are currently a more cost effective replacement for incandescent lighting than LEDs, CFLs are viewed as a transitional technology and have drawbacks such as warm-up time and mercury content requiring hazardous waste disposal. LEDs do not have these drawbacks, and Maritime Electric expects that there will be a much greater uptake of incentives for LED lighting products.

- It is cost effective to incent the installation of "cold climate" air-source heat pumps (units that will operate down to -25 C) in households and businesses with electric resistance space heating. The objective is to have heat pumps installed that will be operating at time of system peak, and thus achieve a reduction in peak load by displacing electric resistance heating.

- It is cost effective to incent the installation of thermostat controls for air-source heat pumps in oil heated households and businesses. The objective is to have these heat pumps turned off during the coldest weather and the oil-fired heating systems operating instead, and thus minimize the impact on system peak. The Company is proposing that a pilot phase of approximately 100 installations be carried out in 2016 to confirm the overall investment required per location and the performance of available control equipment. Assuming a successful pilot phase, full implementation would follow for 2017 to 2020.

- It is not cost effective to incent consumers to purchase ENERGY STAR appliances because 1) manufacturers have already built in most of the cost effective efficiency improvements in order to comply with minimum efficiency performance standards, 2) the additional energy savings offered by ENERGY STAR appliances are relatively small, and 3) for most appliances ENERGY STAR models already dominate the marketplace.

- No incentives are proposed for the purchase of LED holiday lighting. The increase in electric space heating in the past several years is causing the system peak to move from December to January or February. When the system peak occurs in January or February, the reduction in load due to a conversion from incandescent holiday lighting to LED holiday lighting does not result in a corresponding reduction in annual system peak load.

Maritime Electric proposes to recover the costs of the Plan through the Energy Cost Adjustment Mechanism, as was done for DSM programs during 2006 to 2010.

The Company also proposes to recover these costs over periods of up to 15 years in order to match the time period during which the benefits will be realized. Costs incurred prior to the end of the Energy Accord on February 29, 2016 are proposed to be accrued for recovery under revised rates starting March 2016.

The maximum annual amount to be recovered through rates is estimated as $ 1.3 million, which corresponds to 0.65 % of the Company's annual revenue requirement. However, based on the Rate Impact Measure benefit cost analyses for the proposed measures, it is expected that the impact on rates will be minimal.

3.2 INTRODUCTION

During the November 2013 session of the Legislative Assembly of the Province of PEI, the Electric Power Act (the "Act") was amended to require that "… public utilities should utilize energy efficiency and demand-side resource measures whenever it is cost-effective to do so". Energy efficiency and demand-side resource measures are defined in the Act as "any activities, techniques, standards or programs that are or may be used by the public utility to reduce the consumption of electric energy or modify when electric energy is consumed".[1]

According to the Act, the only requirement of energy efficiency and demand-side resource measures proposed for implementation by a public utility is that they be cost effective. However, there can be considerable variation in the assumptions and philosophies that go into determining what is cost effective in the area of energy efficiency and demand side management (DSM). Thus the main body of this report begins with a description of the approach that Maritime Electric uses in doing cost effectiveness analysis of potential energy efficiency and DSM measures.

A description of the California tests for cost effectiveness is included next, along with an example of their application.

Subsequent sections describe the benefit cost analyses of potential energy efficiency measures and potential DSM measures that were considered, along with a summary of the results. Details of the analyses are included in appendices at the end of the report.

The third last section describes customer outreach and public education initiatives, which are proposed as continuation of a number of the Company's current ongoing programs.

[1] Electric Power Act (2014), Preamble and Definitions 1.(1) (b.1): Retrieved from http://www.irac.pe.ca/document.aspx?file=legislation/ElectricPowerAct.asp

The second last section contains the proposed method of recovery of costs through rates.

The final section of the report provides a summary of conclusions and the proposed Plan.

3.3 MARITIME ELECTRIC APPROACH TO COST EFFECTIVENESS ANALYSIS

Cost Effectiveness Evaluated at the Individual Measure Level

In keeping with the Act's requirement that "public utilities should utilize energy efficiency and demand-side resource measures whenever it is cost-effective to do so," Maritime Electric's view is that only measures that are cost effective on a stand-alone basis should be implemented. This approach ensures the cost effectiveness of each potential measure is evaluated on its own merit. Measures are not bundled into programs and then the benefit-cost analysis done at the program level.

In some jurisdictions cost effectiveness tests are applied to a bundle or a portfolio of measures rather than on a stand-alone basis. The result of evaluating potential measures as a bundle is that measures that are not cost effective on their own can end up being recommended for implementation. This is because a bundle of efficiency measures can be deemed to be cost effective (benefit cost ratio of greater than one for the bundle as a whole), with the bundle consisting of some measures that are cost effective on their own (benefit cost ratio of greater than one) and some measures that are not cost effective on their own (benefit cost ratio of less than one).

Various reasons are given in support of the bundle or portfolio approach. These reasons are largely public policy in nature and appear intended to maximize the amount of energy efficiency that is implemented at the expense of some level of cost effectiveness. Maritime Electric's view is that the mandate to provide reliable service at lowest cost requires the Company to implement only measures that are cost effective on their own merit, because it is the Company's customers who will pay for the costs incurred by the Company in implementing energy efficiency measures.

Total Resource Cost Test is the Primary Test of Cost Effectiveness

The benefit-cost analysis done by Maritime Electric on potential energy efficiency and DSM measures is based on the five cost effectiveness tests (sometimes referred to as the "California tests") that were developed in California during the 1980's.

These tests look at cost effectiveness from the perspectives of 1) the participant, 2) the utility, 3) the non-participant, 4) the utility's service area and 5) society as a whole. The use of the California tests is in keeping with industry practice in North America.

The National Action Plan for Energy Efficiency (2008)[2] advises that the Total Resource Cost test and Societal Cost test are used to determine whether energy efficiency is cost-effective overall. In Maritime Electric's analysis the only difference between the Total Resource Cost test and the Societal Cost test is the inclusion of the estimated value of avoided CO2 emissions. Maritime Electric uses the Total Resource Cost test as the primary test of cost effectiveness because the Company is not mandated to internalize and recover the cost of CO2 emissions through rates. In this context the Societal Cost test serves to provide policymakers with an indication of the potential impact of including externalities.

The Participant Cost test, the Utility Cost test and the Rate Impact test indicate how the benefits and costs of energy efficiency and DSM measures are shared between the participant, the utility and the non-participant, respectively. The five benefit-cost tests are further described in section 4.0, including an example of their application.

Cost of Lost Space Heating Taken into Account

Increasing the efficiency of electrical appliances and lighting within a building envelope results in an increase in the amount of energy needed for space heating. This is because most of the electricity used by appliances and lighting ends up as heat inside the building, and thus contributes to space heating. Reducing this contribution to space heating provided by less efficient electricity usage means that more furnace oil must be burned for space heating (in PEI most space heating is done with oil-fired furnaces).

[2] DOE/EPA (2008). *The National Action Plan for Energy Efficiency Vision for 2025: A Framework for Change*: http://www.epa.gov/cleanenergy/documents/suca/vision.pdf

This additional space heating requirement is included as a cost in the cost effectiveness analysis of incenting the purchase of more efficient appliances or lighting.

In some jurisdictions the benefit-cost analysis of efficiency programs does not include the cost to make up for lost space heating. This may be seen as being acceptable in regions outside Atlantic Canada where the heating season is shorter, residential air conditioning is widespread and natural gas is often available for space heating, typically at a lower cost than furnace oil or electricity. However, conditions in Atlantic Canada are different and should be accounted for. The heating season is longer, in the order of eight months, there is relatively little residential air conditioning, and natural gas is generally not available for space heating, making the cost of replacing lost space heating higher.

To estimate the additional furnace oil needed to make up for lost space heating, a factor of 8.5 kWh = 1 litre of furnace oil is used (i.e., 8.5 kWh used by appliances and lighting in the heated space during the heating season will provide the same amount of space heating as 1 litre of furnace oil at 80% conversion efficiency).

In doing cost effectiveness analysis, Maritime Electric uses an 8 month heating season for PEI, which means that two thirds of the electricity saved by using more efficient appliances and lighting in the heated space needs to be replaced with an equivalent amount of additional space heating. Support for using an 8 month heating season for PEI can be found in research done by Canada Mortgage and Housing Corporation (CMHC). In the table below the numbers in the middle two columns are taken from the January 2008 CMHC Research Highlight (Benchmarking Home Energy Savings from Energy-Efficient Lighting – Technical Series 08-101).

TABLE 2 LENGTH OF HEATING SEASON			
Location	**Annual electricity saving due to more efficient lighting (kWh)**	**Space heating increase (litres of furnace oil)**	**Estimated length of heating season (months)**
St. John's, NL	318	30	9.6
Saint John, NB	318	25	8.0
Halifax, NS	318	22	7.1

The numbers in the far right hand column are the result of calculations done by Maritime Electric. Using St. John's as an example, the calculations were done as follows:

- 318 kWh/8.5 kWh per litre = 37 litres of additional furnace oil needed if the heating season were 12 months long; i.e. if all of the electricity saving due to more efficient lighting needed to be replaced with additional space heating

- 12 months x 30 litres/37 litres = 9.6 months estimated length of heating season

PEI is taken to be between the 9.6 months heating season for St. John's and the 7.1 months heating season for Halifax, which leads to using an 8 month heating season for PEI.

3.4 EXPLANATION OF THE CALIFORNIA TESTS FOR COST EFFECTIVENESS

The benefit cost analysis performed for potential DSM programs is based on the five cost effectiveness tests that were developed in California during the 1980's. These tests look at the cost effectiveness of energy efficiency programs from the perspectives of 1) the participant, 2) the utility, 3) the non-participant, 4) the utility's service area or region and 5) society as a whole.

The use of the California tests is in keeping with industry practice in North America. Quoting from the *National Action Plan for Energy Efficiency* (2008), "Currently, five key tests are used to compare the costs and benefits of energy efficiency and demand response programs. These tests all originated in California. … In 1983, California's *Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs* manual developed five cost-effectiveness tests for evaluating energy efficiency programs. These approaches, with minor updates, continue to be used today and are the principal approaches used for evaluating energy efficiency programs across the United States."[3]

These tests are briefly described below.

- The Participant Cost Test looks at cost effectiveness from the perspective of a utility customer who participates in the energy efficiency program. This test takes into account the following benefits and costs to the participating customer:
  - Benefits – the reduction in electricity bills and the incentive rebate received.
  - Costs – the cost to implement the efficiency measure (does not take into account the incentive rebate) and the cost to replace lost space heating.

[3] *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers.* Energy and Environmental Economics, Inc. and Regulatory Assistance project (2008): http://www.epa.gov/cleanenergy/energy-programs/suca/resources.html

- The Utility Cost Test looks at cost effectiveness from the perspective of the utility that undertakes the energy efficiency program. This test takes into account the following benefits and costs to the utility:
  - Benefits – avoided capacity costs and avoided energy supply costs.
  - Costs – the cost to develop and administer the energy efficiency program, and the cost of incentive rebates to customers.
- The Rate Impact Measure Test looks at cost effectiveness from the perspective of a utility customer who does not participate in the energy efficiency program by examining the effect of the program on the utility's rates. This test takes into account the following benefits and costs to the utility:
  - Benefits – avoided capacity costs and avoided energy supply costs.
  - Costs – the cost to develop and administer the energy efficiency program, the cost of incentive rebates to customers and the reduction in revenue due to reduced energy sales.
- The Total Resource Cost Test looks at cost effectiveness from the perspective of the entire area or region that the utility serves. This test takes into account the following benefits and costs to the region as a whole:
  - Benefits – avoided capacity costs and avoided energy supply costs by the utility.
  - Costs – the utility's cost to develop and administer the energy efficiency program (not including the incentive rebates), the cost to customers to implement the energy efficiency measure and the cost to customers to replace lost space heating.
- The Societal Cost Test looks at cost effectiveness from a broader perspective than the Total Resource Cost Test. In addition to all the benefits and costs included in the Total Resource Cost Test, the Societal Cost Test takes into account societal benefits such as avoided emissions to the environment that result from the energy efficiency program.

As an example of the use of the tests, the following table shows the application of the five tests to a potential rebate coupon that would incent consumers to purchase an ENERGY STAR refrigerator instead of a unit that just meets the minimum efficiency performance standards. Except for the increment in price to purchase the ENERGY STAR refrigerator and the amount of the incentive rebate, all the benefits and costs are present value amounts that are estimated to accrue over the service life of the appliance.

TABLE 3 BENEFIT COST ANALYSIS FOR POTENTIAL ENERGY STAR REFRIGERATOR REBATE					
	Participant Cost test ($)	**Utility Cost test ($)**	**Rate Impact test ($)**	**Total Resource test ($)**	**Societal Cost test ($)**
Benefits:					
Utility avoided generating capacity cost		8	8	8	8
Utility avoided T&D capacity cost		9	9	9	9
Utility avoided energy supply cost		43	43	43	43
Reduction in participant utility bills	71				
Incentive rebate to participant	30				
Value of avoided CO2 emissions					9
Total	101	60	60	60	69
Costs:					
Utility DSM program admin. costs		10	10	10	10
Utility DSM program rebate costs		30	30		
Revenue reduction to utility			62		
Higher price for ENERGY STAR refrigerator	50			50	50
Cost to replace lost space heating	39			39	39
Total	89	40	102	99	99
Net benefit (cost)	12	20	(42)	(39)	(30)
Benefit / cost ratio	1.13	1.50	0.58	0.60	0.69

Based on the analysis in the above table, the benefit-cost ratio for the Total Resource Cost Test is less than 1.0 (equal to 0.60), which means that the benefits do not outweigh the costs for the potential refrigerator rebate coupon measure, and thus it would not be recommended for implementation.

3.5 ANALYSIS OF POTENTIAL ENERGY EFFICIENCY MEASURES

3.5.1 Lighting

Maritime Electric is proposing a rebate coupon measure aimed at incenting consumers to choose Light Emitting Diode (LED) products. The coupon will be for $ 5.00, and it will apply to all LED light bulbs.

The rationale for this initiative is based in part on benefit cost analyses done for:

- LED replacement for the 43 Watt incandescent halogen standard light bulb
- LED replacement for the BR30 incandescent reflector bulb typically used in ceiling pot-light fixtures

The expectation is that by partially offsetting the higher price for LEDs with the rebate coupon, LEDs will gain widespread acceptance sooner than would be the case without the rebate. The benefit cost analyses that support these measures is based on an expected advancement in consumer uptake of LED lighting by 10 years.

Phase out of Standard Incandescent Light Bulbs

On January 1, 2014 new federal minimum efficiency regulations for general service incandescent lighting came into effect. These regulations are intended to result in the phase out of standard incandescent light bulbs in 75 and 100 Watt sizes. Similar regulations for standard incandescent light bulbs in 40 and 60 Watt sizes came into effect on December 31, 2014.

These regulations require at least a 28% reduction in electricity usage to provide the same amount of general service lighting. In the absence of incentives to purchase LED lighting, Maritime Electric expects that consumers will respond as follows:

- By 2008 consumers were purchasing one compact fluorescent (CFL) bulb for every three standard incandescent bulbs, according to the National Electrical Manufacturers Association's quarterly reports on shipments of general service light bulbs in the United States. However, the penetration of CFLs has not increased above the 25 % level since 2008, presumably due to their drawbacks. Maritime Electric expects that this will continue to be the case, with CFLs eventually being replaced by LED bulbs in the longer term as the price of LEDs decreases over time.

- Due to the drawbacks of CFLs and the higher price of LEDs, consumers will purchase incandescent halogen bulbs to replace standard incandescent bulbs as they are removed from the marketplace. The incandescent halogen bulb is identical in appearance to the standard incandescent bulb but lasts three times as long (3,000 hours instead of 1,000 hours) and just meets the 28 % required improvement in efficiency (e.g. 72 Watts instead of 100 Watts and 43 Watts instead of 60 Watts).

Replacement for 43 Watt incandescent halogen

To assess the possibility of achieving additional savings in household energy usage for lighting, two energy saving alternatives to the 43 Watt incandescent halogen light bulb are compared in the following two tables.

TABLE 4
ENERGY SAVING ALTERNATIVES TO THE 43 WATT INCANDESCENT HALOGEN LIGHT BULB

	Incandescent Halogen	Compact Fluorescent (CFL)	Light Emitting Diode (LED)
Power used (Watts)	43	13	11
Operating life (hours)	3,000	6,000	25,000
Indicative retail price	$ 2.50	$ 3.50	$ 10.50

TABLE 5 BENEFIT COST ANALYSIS RESULTS FOR REBATE COUPON FOR 11 WATT LED	
Potential Measure	**Benefit cost ratio for Total Resource Cost test**
Replace 43 Watt incandescent halogen with 13 Watt CFL	2.67
Replace 43 Watt incandescent halogen with 11 Watt LED	1.53
Replace 13 Watt CFL with 11 Watt LED	0.41
Replace one 43 Watt incandescent halogen and one 13 Watt CFL with two 11 Watt LEDs	1.17

Based on the above two tables, it appears that the best choice from a least cost perspective is the 13 Watt CFL. However, CFLs have some drawbacks that have limited consumer acceptance of them. These are:

- Typically CFLs take one to two minutes to reach full brightness
- Some are not dimmable
- They contain mercury, and thus should not be disposed of in the normal household waste stream

To achieve energy savings in excess of the 28 % that incandescent halogens will provide in replacing standard incandescent bulbs, Maritime Electric is proposing to offer a $ 5.00 rebate coupon for general service LEDs. A $ 5.00 rebate is in line with other jurisdictions and offers a significant reduction in the cost of an LED bulb to the consumer. It is expected that some people will use the coupon to purchase an LED to replace a CFL instead of an incandescent halogen. However the benefit cost analysis shows a benefit cost ratio of 1.17 for the Total Resource Cost test even if one 13 Watt CFL is replaced for every 43 Watt incandescent halogen that is replaced. If customer uptake is greater than expected, the cost of the program can be controlled by limiting the number of rebate coupons made available.

Replacement for BR30 Incandescent Reflector Light

Reflector type light bulbs have not been made subject to minimum efficiency performance standards. Therefore the 65 Watt incandescent reflector bulb used in pot lights will continue to be available to consumers. Two energy saving alternatives to the 65 Watt incandescent reflector bulb are compared in the following table.

TABLE 6
ENERGY SAVING ALTERNATIVES TO THE 65 WATT BR30 INCANDESCENT REFLECTOR BULB

	BR30 incandescent reflector bulb	CFL reflector bulb	LED reflector bulb
Power usage (Watts)	65	16	13
Operating life (hours)	2,000	6,000	25,000
Indicative retail price	$2.50	$ 7.50	$ 17.00

Similar to the case for replacement of the 43 Watt incandescent halogen, the benefit cost ratio for the Total Resource Cost test is greater than 1.0 for a $ 5.00 rebate coupon for the LED reflector bulb, even if the number of 16 Watt CFL reflector bulbs replaced is the same as the number of 65 Watt incandescent reflector bulbs replaced.

TABLE 7
BENEFIT COST ANALYSIS RESULTS FOR REBATE COUPON FOR 13 WATT LED REFLECTOR BULB

Potential Measure	Benefit cost ratio for Total Resource Cost test
Replace 65 Watt BR30 incandescent reflector with 16 Watt CFL reflector bulb	2.04
Replace 65 Watt BR30 incandescent reflector with 13 Watt LED reflector bulb	1.67
Replace 16 Watt CFL reflector with 13 Watt LED reflector	0.62
Replace one 65 Watt BR30 incandescent reflector and one 16 Watt CFL reflector with two 13 Watt LED reflectors	1.38

The results of the above benefit cost analyses are assumed to be indicative for LED light bulbs generally, and thus for simplicity of program delivery Maritime Electric is proposing that the $ 5.00 rebate coupon will apply to all LED light bulbs.

Estimated Energy and Demand Savings and Cost of LED Rebate Coupon Program

The table below shows the estimated reduction in system energy and peak load as a direct result of the LED rebate coupon program, based on an average of eight incandescent halogen bulbs per household replaced with LEDs over five years (an annual saving of 187 kWh per household at the end of five years).

TABLE 8 ESTIMATED ENERGY AND DEMAND SAVINGS AT END OF FIVE YEARS DUE TO LED REBATE COUPON	
Number of halogen bulbs replaced per household	8
Number of MECL Residential customers	58,000
Total number of halogen bulbs replaced	464,000
Estimated reduction in annual energy supply (GWh)	12.2
(based on (43 – 11) Watts x 2 hours per day and 11.5 % losses)	
Estimated reduction in system peak load (MW)	5.9
(based on (43 – 11) Watts x 1/3 on at peak and 15.7 % losses)	

The estimated cost of the five year LED rebate coupon program is shown in the table below. A 50 % free ridership is assumed; i.e. one CFL is replaced for each incandescent halogen that is replaced. The administration cost of $ 1.50 per coupon is based on discussions with a company that does rebate coupon processing.

TABLE 9 ESTIMATED COSTS FOR FIVE YEAR LED REBATE COUPON PROGRAM	
Number of halogen bulbs replaced per household	8
Number of MECL Residential customers	58,000
Total number of halogen bulbs replaced	464,000
Cost of coupons that replace halogens (at $ 5.00 each)	$ 2,320,000
Cost of coupons that replace CFLs (at $ 5.00 each)	$ 2,320,000
Administration cost (at $ 1.50 per coupon)	$ 1,392,000
Total Program Cost	$ 6,032,000

LED Holiday Lighting

In 2010 Maritime Electric proposed a rebate coupon program for LED holiday lighting as a measure to reduce the system peak load. The program was based on the expectation that the conversion to LED holiday lighting would be advanced by 10 years. A similar program has not been included in the current proposed Plan because of the increase in electric space heating during the past several years, as the increase in electric space heating is causing the system peak load to shift from December to January or February. When the system peak occurs in January or February, the reduction in load due to a conversion from incandescent holiday lighting to LED holiday lighting does not result in a corresponding reduction in annual system peak load.

3.5.2 Household Appliances

Introduction

Maritime Electric is not proposing any measures to incent consumers to purchase more efficient household appliances. The reasons for this are:

- Manufacturers have already incorporated most cost-effective efficiency improvements into the major household appliances in order to comply with government minimum efficiency regulations.

- The energy efficiency program opportunity lies in incenting consumers to purchase appliances that are more efficient than the minimum standards, and in particular those appliances that meet the ENERGY STAR criteria. However, the results of benefit cost analyses show that it would not be cost effective for the Company to do so, largely because the additional savings are relatively small.

- The ENERGY STAR program has been a success – the majority of consumers are already purchasing ENERGY STAR qualified appliances.

Impact of Minimum Efficiency Performance Standards

To illustrate the limited opportunity for efficiency programs with respect to household appliances, the following table summarizes the annual average electricity usage of major new appliances for selected years of manufacture, starting with 1990. An examination of the table shows that large improvements in energy efficiency have been achieved over the years, driven in large part by government minimum efficiency performance standards and the ENERGY STAR program.

TABLE 10
AVERAGE ANNUAL ENERGY CONSUMPTION (kWh/year) OF NEW MAJOR APPLIANCES

	1990	1997	2001	2010
Refrigerators (16.5 – 18.4 cu. ft.)				
▪ Standard Top-Mounted Freezer	1044	664	572	427
▪ ENERGY STAR qualified	-	-	440	369
Freezers (Standard size Chest)	658	342	337	295
Kitchen ranges (30 inch)				
▪ Self-Cleaning	727	759	741	530
▪ Non-Self-Cleaning	786	780	786	499
Dishwashers (includes water heating)				
▪ Standard size	1026	649	634	310
▪ ENERGY STAR qualified	-	-	534	309
Clothes Washers (includes water heating)				
Standard size (Top-Loading)	1218	930	905	319
▪ ENERGY STAR qualified	-	-	304	148
Clothes Dryers (Standard size)	1103	887	916	928

Source: Natural Resources Canada (2013). *Choosing and Using Appliances with Energuide*: http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/pdf/energystar/EnerGuideappliances.pdf

Table 10 suggests that refrigerators and clothes washers are the two appliances with potential for energy savings through purchase of Energy Star qualified models. However, revised minimum efficiency performance standards that came into effect on September 15, 2014 for refrigerators and on March 7, 2015 for clothes washers will further reduce the potential for energy savings. The benefit cost analysis of potential rebate coupon measures to incent consumers to purchase ENERGY STAR refrigerators and clothes washers shows benefit cost ratios of less than 1.0 for the Total Resource Cost test, and thus such measures have not been proposed.

ENERGY STAR Market Share

ENERGY STAR® is a U.S. Environmental Protection Agency (EPA) voluntary program that helps businesses and individuals improve comfort, save money, and reduce both energy usage and emissions of greenhouse gases (GHGs) through superior energy efficiency.

Canada is an international partner in the U.S. Energy Star program since 2001. Natural Resources Canada (NRCan) administers and monitors use of the ENERGY STAR name and symbol in Canada under an agreement with the U.S. EPA. NRCan works with the EPA to develop ENERGY STAR technical specifications for products. It also develops Canadian specifications for certain ENERGY STAR qualified products. Typically, an ENERGY STAR qualified product is in the top 15 to 30 percent of its class for energy performance.

The following table shows historical U.S. ENERGY STAR market share growth for selected major appliances. An examination of this table indicates that the North American major appliance market has been largely transformed by the ENERGY STAR program, given the high levels of market share attained by ENERGY STAR models.

TABLE 11
U.S. ENERGY STAR APPLIANCES: MARKET SHARE

	2008	2009	2010	2011	2012	2013	Revision Status
Refrigerators	31 %	35 %	50 %	56 %	76 %	74 %	V5.0
Freezers			25 %	21 %	44 %	29 %	V5.0
Room ACs	43 %	36 %	33 %	62 %	58 %	-	V3.0
Clothes Washers	24 %	48 %	64 %	60 %	66 %	66 %	V6.1 V7.0 (Mar 2015)
Dishwashers	67 %	68 %	100 %	96 %	89 %	90 %	V6.0

Source: Environmental Protection Agency (2014). *ENERGY STAR Appliance Specification Updates*
http://www.energystar.gov/ia/partners/downloads/ENERGY_STAR_Appliance_Specification_Updates_Webinar.pdf?0b55-1475
Source: U.S. ENERGY STAR Program (2014). *ENERGY STAR® Unit Shipment and Market Penetration Report Calendar Year 2013 Summary.*
https://www.energystar.gov/ia/partners/downloads/unit_shipment_data/2013_USD_Summary_Report.pdf?e143-f3e4

Refrigerator Roundup

Some households have two refrigerators, often as a result of keeping the old refrigerator when a new one is purchased. The old refrigerator is moved to another part of the house, and often kept plugged in. In some jurisdictions there is a program under which homeowners are offered a nominal payment for their second refrigerator, and it is removed from the home.

Maritime Electric's benefit cost analysis for such a program gave a benefit cost ratio of 0.76 for the Total Resource Cost test, and thus it has not been proposed.

3.6. ANALYSIS OF DEMAND SIDE MANAGEMENT MEASURES

3.6.1 Air-Source Heat Pumps - General

Currently the PEI Office of Energy Efficiency ("OEE") incents the installation of "most efficient" heat pumps by providing a $425 grant for units with a Heating Season Performance Factor ("HSPF") of 8.35 or better for Region 5. Maritime Electric is proposing two measures for heat pumps that will tie in with OEE's grant program. By partnering with OEE, Maritime Electric expects to reduce administration costs and leverage its grant by having it and the OEE grant coupled together.

1. For homes with electric resistance heating, Maritime Electric proposes to offer a matching grant for the installation of heat pumps that meet OEE's efficiency criterion <u>and</u> are rated to operate down to temperatures as low as -25 C. The objective is to have heat pumps installed that will be operating at system peak, and thus reduce system peak load by displacing some of the electric resistance heating that would otherwise be on.

2. For homes with oil-fired heating, Maritime Electric proposes to offer an annual rebate on customers' bills or similar incentive for the installation of heat pumps that meet OEE's efficiency criterion <u>and</u> that will turn off at temperatures below -15 C. The objective is to have these heat pumps off at system peak, and the oil-fired furnaces supplying all the space heating requirements. Approximately half of the annual rebate on customers' bills would be to compensate homeowners for the extra cost incurred by having the heat pumps turned off at temperatures below -15 C.

The benefit cost analyses that support the recommendation of these two measures are shown in Appendix 13 and Appendix 14.

For homes with oil heat, the turning off of heat pumps at temperatures below -15 C would be done by a thermostat switch installed inside the heat pump. MECL is proposing a pilot phase of approximately 100 installations for 2016. The purpose of the pilot phase is to confirm the technical viability of turning off the heat pumps, and to confirm that the expected benefits will be realized. Assuming a successful pilot phase, full implementation for the program would follow for 2017 to 2020.

Approximately 3,600 heat pumps were installed in PEI in 2013. The estimated resulting impact on system peak load is shown in the following table.

TABLE 12
ESTIMATED ADDITION TO PEAK LOAD BY HEAT PUMPS INSTALLED IN 2013

	Units Rebated by OEE	**Units not Rebated**	**Total**
Estimated number of units installed in 2013	900	2,700	3,600
Estimated percentage that are on at system peak	75	50	56
Number of units on at system peak	675	1,350	2,025
Estimated usage by each unit at peak (kW)	1.6	1.6	1.6
Total load at peak (including 15.7 % losses) (MW)	1.3	2.5	3.8
Less electric resistance heating displaced (MW)	0.3	0.5	0.8
Net addition to system peak load (MW)	**1.0**	**2.0**	**3.0**

The 0.8 MW of electric resistance heating displaced was estimated as follows:

- An estimated 10 % of Island households have electric resistance heating. Thus 10 % of the heat pump load at peak (i.e. 3.8 MW x 0.1 = 0.38 MW) was displacing electric resistance heating.
- Assuming a Coefficient Of Performance (COP) of 2.0 at time of system peak for the heat pumps, the 0.38 MW of heat pump load was displacing 0.38 MW x 2.0 = 0.76 MW (rounded to 0.8 MW in above table) of electric resistance heating.

3.6.2 "Cold Climate" Heat Pumps for Homes with Electric Resistance Heating

An estimated 10% of Island households have electric resistance heating. This means that of the 3,600 heat pumps installed in 2013, 10%, or 360, were installed in homes with electric resistance heating. Of these, an estimated 56%, or approximately 200, were on at system peak and thus displacing the 0.8 MW (0.76 MW rounded) of electric resistance heating shown in the Table 12 above, for an overall net reduction of 0.38 MW (the 0.76 MW reduction in resistance heating minus the 0.38 MW used by the heat pumps – this assumes a COP of 2.0 at system peak).

If all 360 units installed in electric resistance heated homes in 2013 were on at system peak (instead of the estimated 200 units), there would be an additional 0.76 MW x 160/200 = 0.6 MW of electric resistance heating displaced, for an additional net reduction of 0.3 MW. This represents an opportunity to mitigate the impact on system peak load of electric resistive heating.

There will also be an associated reduction in energy usage. The heat pumps not on at peak are assumed to turn off at -15 C. On average, it is estimated that each unit that turns off at -15 C would have displaced an additional 722 kWh of electric resistance heating had it kept operating down to -25 C, for a net reduction of 361 kWh (722 kWh/COP of 2.0).

In partnership with the OEE, MECL proposes to provide a matching grant of $425 for cold climate heat pumps installed in electric resistance heated households and businesses. This would be in addition to the $425 grant currently provided by the OEE. In addition to a sharing of administration costs, the tie in with the OEE grant program would be the OEE revising its grant criteria to include the requirement that the heat pump must be rated to operate down to -25 C.

Measure Criteria

1. Cold climate heat pump must operate down to -25 C.

2. Cold climate heat pump must meet the OEE's efficiency criterion – based on NRCan's "most efficient" HSPF designation of greater than 8.35 HSPF for climate zone Region 5.

Annual Cost

Cost of grants	360 units/y x $ 425 =	$ 153,000
Shared admin cost with OEE	360 units/y x $ 150 =	$ 54,000
Total annual cost (MECL)		$ 207,000

Estimated Energy Saving and Peak Load reduction in Year 5

0.3 GWh of energy: (361 kWh/unit x 160 units / year x 5 years and 11.5% losses)

1.5 MW of peak load: (0.3 MW/year x 5 years)

3.6.3 Thermostat Shutoff of Heat Pumps for Homes with Oil Furnaces

Of the 900 units given grants by OEE in 2013, an estimated 90 %, or 810, were installed in homes or businesses with oil or some other fuel heat. Of these, an estimated 608 units, or 75 %, were on at system peak, representing a load of 1.15 MW (1.6 kW x 608 units and 15.7 % losses). The ability to shut these units off below a certain temperature (proposed at - 15 C and below) would represent an opportunity to mitigate the impact on system peak load of heat pump installations.

Based on turning off the units at -15 C and below, a typical homeowner would see an annual reduction in electricity usage of 361 kWh, but would also see a corresponding increase in furnace oil usage of 85 litres (361 kWh x COP of 2.0/8.5 kWh per litre = 85 litres), for an overall increase in their energy costs. Approximately half of a proposed annual electricity bill credit is intended to compensate the homeowner for this increase in energy costs (the other half of the bill credit would serve as an additional incentive for customers to participate in the program).

Another issue to consider is that in some years the reduction in peak load achieved will be less than the full amount of the heat pump load. An example would be a year in which the system peak occurs at a temperature of -14 C, when the heat pumps would still be running. To account for this, a factor of 0.5 is applied to the amount of heat pump load under thermostat control in estimating the expected reduction in system peak load.

If the thermostats were set to turn the heat pumps off at -12 C and below, then the resulting reduction in peak load would be larger than for a -15 C shut off temperature. However, the overall increase in the homeowner's energy costs would be larger, because the heat pump would be shut off for more hours and more furnace oil would be used.

To better assess what is the optimal shut off temperature, and to confirm the technical viability of the proposed thermostat control, Maritime Electric is proposing a pilot phase of approximately 100 installations for 2016. Assuming a successful pilot phase, full implementation of the program would follow for 2017 to 2020.

In partnership with the OEE, MECL proposes to provide an annual bill credit of $100 or a similar incentive for cold climate heat pumps installed in oil heated households and businesses. This would be in addition to the $425 grant currently provided by the OEE. In addition to a sharing of administration costs, the tie in with the OEE grant program would be the OEE making the availability of its grant subject to the homeowner agreeing to thermostat control of the heat pump. Existing installations would be eligible for the program (but not for the OEE $425 grant).

Measure Criteria

1. Cold climate heat pump must be rated to operate down to -25 C.
2. Cold climate heat pump must meet the OEE's efficiency criterion – based on NRCan's "most efficient" HSPF designation of greater than 8.35 HSPF for climate zone Region 5.
3. Cold climate heat pump must have thermostat controlled shut off (installed at Maritime Electric's expense, and a Maritime Electric installed meter to monitor heat pump operation).

Annual Cost (after first year pilot phase)

Cost for meter and thermostat	810 units/y x $500 =	$ 405,000
Annual bill credit	810 units/y x $100 =	$ 81,000
Shared admin cost with OEE	810 units/y x $150 =	$ 121,500
Total annual cost (MECL)		$ 607,500

In addition to the above costs, the annual bill credits would continue past 2020 for the service life of the heat pumps, estimated to be 15 years. The total for bill credits post 2020 is estimated as $ 4.2 million.

Estimated Energy Saving and Peak Load reduction in Year 5

1.0 GWh of energy: (361 kWh/unit x 608 units/year x 4 years and 11.5% losses)

2.3 MW of peak load: (1.6 kW unit x 608 units/year x 0.5 x 4 years and 15.7% losses)

3.7 SUMMARY OF BENEFIT COST ANALYSES

The following table summarizes the results of the benefit cost analyses for all potential measures analyzed.

TABLE 13
BENEFIT COST RATIOS FOR POTENTIAL ENERGY EFFICIENCY AND DSM MEASURES

Potential Measure	Appendix	Participant Cost Test	Utility Cost Test	Rate Impact Test	Total Resource Cost Test	Societal Cost Test
Replace 43 W halogen with 13 W CFL	2	1.95	n/a	1.63	2.67	2.88
Replace 43 W halogen with 11 W LED	3	1.58	3.86	1.14	1.53	1.65
Replace 13 W CFL with 11 W LED	4	1.21	0.24	0.21	0.41	0.43
Replace 43 W halogen and 13 W CFL with two 11 W LEDs	5	1.49	2.05	0.90	1.17	1.26
Replace 65 W BR30 with 16 W CFL	6	1.90	7.28	1.33	2.04	2.19
Replace 65 W BR30 with 13 W LED	7	1.53	6.27	1.29	1.67	1.80
Replace 16 W CFL BR30 with 13 W LED	8	1.26	0.36	0.30	0.62	0.64
Replace 65 W BR30 and 16 W CFL BR30 with two 13 W LEDs	9	1.47	3.32	1.09	1.38	1.48
Rebate for ENERGY STAR refrigerator	10	1.13	1.49	0.58	0.60	0.69
Rebate for ENERGY STAR clothes washer	11	1.51	1.54	0.60	0.93	1.10
Refrigerator Roundup program	12	1.93	1.42	0.56	0.76	0.88
Heat pumps that operate to -25 C for homes with electric resistance heat	13	1.42	3.68	2.66	3.66	3.74
Thermostat shut off for heat pumps in homes with oil heat	14	1.58	1.63	1.24	1.78	1.78

3.8 CUSTOMER OUTREACH ACTIVITIES

Working with the community through outreach programs is an ongoing part of the Company's energy conservation strategy. These programs are intended to enhance energy conservation and awareness to help customers better understand their energy use. These activities also provide opportunities to promote the Company`s incentive rebate programs.

Participation in tradeshows, presentations, promotions and lighting exchanges will continue to be an integral component of the DSM plan. A series of promotions and events will occur annually to help consumers understand more about energy efficiency and conservation. Marketing of proposed DSM programs will include newspaper and radio. Additional training about energy efficiency and conservation will be provided for Customer Service staff.

Over the next five years further modifications will be made to the Company's customer information and website in order to provide updated energy conversation information, tools and program information for customers.

Maritime Electric plans to partner with the OEE to develop energy efficiency communications and information programming for the commercial sector, including seminars and workshops. These initiatives will focus on demand management as well as energy efficiency.

The Company proposes to spend $ 167,500 annually on customer outreach activities.

3.9 PROPOSED RECOVERY OF COSTS THROUGH RATES

Table 14 lists the proposed incentive measures and the estimated implementation cost for each measure.

TABLE 14
SUMMARY OF PROPOSED EXPENDITURES

Proposed Measure	Estimated cost for years 2015 - 2020 ($ millions)	Estimated ongoing costs after 2020 ($ millions)
$ 5.00 rebate coupon for LED light bulbs	$ 6.0	
Grants for heat pumps that operate down to -25 C in electric resistance heated homes	$ 1.0	
Incentives for thermostat controlled heat pumps in oil heated homes	$ 3.1	$ 4.2
Community Outreach Activities	$ 0.8	
TOTAL	$ 10.9	$ 4.2

Appendix 15 shows the estimated annual expenditures for 2016 to 2020, and for post 2020. The annual bill credits or similar incentives for thermostat controlled heat pumps would continue for the service life of the heat pumps, estimated to be 15 years.

The Company proposes to recover these costs through the Energy Cost Adjustment Mechanism, as follows:

- Over 10 years for the LED rebate coupons, based on an assumed advancement of LED purchases by 10 years
- Over 15 years for the heat pump measures, based on an assumed 15 years life for a mini-split heat pump (Except for bill credits, which would be expensed as incurred.)
- Expensed as incurred for Community Outreach Activities

Appendix 16 shows the proposed annual recovery of costs through rates. Appendix 16 shows that the maximum annual amount to be recovered through rates is $ 1.3

million, which corresponds to approximately 0.65 % of the Company's annual revenue requirement. However, based on the benefit cost ratios for the Rate Impact Measure (RIM) tests for the proposed measures being close to or greater than 1.0, it is expected that the impact on rates will be minimal. (A RIM benefit cost ratio of 1.0 or greater for a measure indicates that implementation of the measure will not result in an increase in electricity rates, and thus it will not negatively impact customers who do not participate in the measure.)

It is proposed that costs incurred prior to the end of the Energy Accord on February 29, 2016 will be accrued for recovery under revised rates starting March 1, 2016.

3.10 CONCLUSIONS AND PROPOSED PLAN

The Company's proposed Plan is based on the following observations and conclusions:

- It is cost effective to incent consumers to use LED lighting products, primarily because the LEDs are longer life and more efficient than incandescent lighting.

- No incentives will be offered for the purchase of CFL lighting products because it is expected that there is limited consumer appetite for increased use of CFLs. Even though CFLs are currently a more cost effective replacement for incandescent lighting than LEDs, CFLs are viewed as a transitional technology because of drawbacks such as warm-up time and mercury content. LEDs do not have these drawbacks, and Maritime Electric expects that there will be a much greater uptake of incentives for LED lighting products.

- It is cost effective to incent the installation of "cold climate" air-source heat pumps in households and businesses with electric resistance space heating. The objective is to have only heat pumps installed that will be operating at time of system peak, and thus achieve a reduction in peak load by displacing electric resistance heating.

- It is cost effective to incent the installation of thermostat controls for air-source heat pumps in oil heated households and businesses. Here the objective is to have the heat pumps shut off during the coldest weather. By having the oil furnace supplying all the space heating for the building during the coldest weather, the impact on system peak load will be minimized. It is proposed that a pilot phase of approximately 100 installations be carried in 2016 out to confirm the overall investment required per location and the performance of available control equipment. Assuming a successful pilot phase, full implementation of the program would follow for 2017 to 2020.

- It is not cost effective to incent consumers to purchase ENERGY STAR appliances because 1) manufacturers have already built in most of the cost effective efficiency improvements in order to comply with minimum efficiency performance standards, 2) the additional energy savings offered by ENERGY STAR appliances are relatively small, and 3) for most appliances ENERGY STAR models already dominant the marketplace.

- No incentives are proposed for the purchase of LED holiday lighting. The increase in electric space heating in the past several years is causing the system peak to move from December to January or February. When the system peak occurs in January or February, the reduction in load due to a conversion from incandescent holiday lighting to LED holiday lighting does not result in a corresponding reduction in annual system peak load.

Table 15 below lists the proposed incentive measures, the reduction in energy and peak load expected to be realized through each measure, and the estimated implementation cost for each program. The energy and peak load reductions are estimated annual values for year 5 (i.e. 2020), while the costs are the total estimated expenditures for the five year period 2016 to 2020.

The Company expects that the proposed Plan will satisfy Section 16.1(5)(d) of the Electric Power Act, which requires that the Plan submitted "shall be designed so that it is reasonably likely, on implementation, to achieve the results expected by the order".

TABLE 15 SUMMARY OF 2015 – 2020 PROPOSED ENERGY EFFICIENCY AND DSM MEASURES				
Proposed Measure	**Expected annual energy saving in year five (GWh)**	**Expected peak load reduction in year five (MW)**	**Estimated cost for the five years ($ millions)**	**Estimated cost for after 2020 ($ millions)**
$ 5.00 rebate coupon for LED light bulbs	12.2	5.9	$ 6.0	
Grants for heat pumps that operate down to -25 C in electric resistance heated homes	0.3	1.5	$ 1.0	
Incentives for thermostat controlled heat pumps in oil heated homes (1)	1.0	2.3	$ 3.1	$ 4.2
Customer Outreach Activities			$ 0.8	
TOTAL	**13.5**	**9.7**	**$ 10.9**	**$ 4.2**

(1)Based on a successful pilot phase in 2016 and full implementation for 2017 to 2020

The Company proposes to recover these costs through the Energy Cost Adjustment Mechanism, as was done for DSM programs during 2006 to 2010.

The Company also proposes to recover these costs over a period of up to 15 years in order to match the time period during which the benefits will be realized. Costs incurred prior to the end of the Energy Accord on February 29, 2016 are proposed to be accrued for recovery under revised rates starting March 1, 2016.

The maximum annual amount to be recovered through rates is estimated as $ 1.3 million, which corresponds to 0.65 % of the Company's annual revenue requirement. However, based on the benefit cost ratios for the Rate Impact Measure (RIM) tests for the proposed measures being close to or greater than 1.0, it is expected that the impact on rates will be minimal. (A RIM benefit cost ratio of 1.0 or greater for a measure indicates that implementation of the measure will not result in an increase in electricity rates, and thus it will not negatively impact customers who do not participate in the measure.)

4.0 PROPOSED ORDER

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY
AND APPEALS COMMISSION

IN THE MATTER of Section 16.1 of the Electric Power Act (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission approving an Energy Efficiency and Demand Side Management Plan for the years 2015 to 2020 and for certain approvals incidental to such an Order.

UPON receiving an Application by Maritime Electric Company, Limited (the "Company") for approval of an Energy Efficiency and Demand Side Management Plan (the "Plan") for the years 2015 to 2020 and certain approvals incidental to such an order;

AND UPON considering the Application as well as the Evidence of the Company;

NOW THEREFORE for the reasons given in the annexed Reasons for Order;
IT IS ORDERED THAT

1. The Energy Efficiency and Demand Side Management Plan as detailed in the evidence for the years 2015 to 2020 is approved;
2. The inclusion of the Plan costs in the ECAM account is approved;

3. Commencing in 2017, and until otherwise directed, the Company shall file, no later than April 30th each year, an annual progress report on the status of the Plan; and
4. The Company shall seek Commission approval for any additional programs or initiatives affecting the Plan.

DATED at Charlottetown this ____ day of ____, 2015

BY THE COMMISSION:

____

__________________, Chair

____

__________________, Commissioner

____

__________________, Commissioner

Appendix 1
INPUTS AND ASSUMPTIONS FOR BENEFIT COST ANALYSIS

1. The following life expectancies for the major household appliances have been used. They are from the 2010 EnerGuide Appliance Directory.

Dishwashers -	13 years	Electric ranges -	16 years
Clothes washers -	14 years	Refrigerators -	18 years
Clothes dryers -	16 years	Freezers -	19 years

2. An annual escalation rate of 2.0% has been assumed.

3. Maritime Electric's weighted average cost of capital has been used as the discount rate in all the cost effectiveness tests. This is equal to 7.0%, based on 41.5% equity at 9.75% return and 58.5% long term debt at 5.0% interest rate.

4. Maritime Electric's average annual transmission and distribution system losses are 7.5%. However, on an incremental basis, the energy losses are estimated to be 11.5%. This means that 100 kWh saved at the customer's premises will result in a 100 kWh/(1 - 0.115) = 113 kWh reduction in the amount of energy that the utility must generate or purchase. The present worth of the utility's avoided energy supply cost is then (kWh saved by customer/(1 - 0.115)) x $/kWh x PV factor.

5. The estimated incremental transmission and distribution system losses at the time of system peak are 15.7%. This means that 1.0 kW saved at the customer's premises at the time of system peak will result in a 1.0 kW/(1 - 0.157) = 1.19 kW reduction in system peak load. Also, Maritime Electric must maintain a planning reserve capacity equal to 15% of firm peak load. Thus the present worth of the utility's avoided capacity cost is then (kW saved by customer/(1 - 0.15)) x 1.15 x $/kW-year x PV factor.

6. An CO2 emissions rate of 0.60 kg/kWh has been assumed as an indicative value. Natural gas fired combined cycle generation is lower than 0.60 kg/kWh, while coal and oil fired generation are higher. Maritime Electric' marginal source of energy supply is normally purchases from the mainland, which typically are priced based on natural gas fired generation. The Company's on-Island oil fired generating units normally only run in the order of 100 to 200 hours in a year.

7. An value of $40/tonne has been used in the Societal Cost test as an indicative value for the cost of CO2 emissions. This is based on the May 2103 revision by the U.S. Office of Management and Budget (OMB) of its estimate of the social cost of CO2 emissions. The revised OMB value was based on the results of updated climate change modeling.

9. The Residential rate first block energy charge was used in all cost effectiveness analyses. With a first block size of 2,000 kWh per month, it is expected that most usage for lighting, appliances and mini-split heat pumps is billed at the first block energy charge.

Appendix 2

BENEFIT COST ANALYSIS OF REPLACING 43 WATT INCANDESCENT HALOGEN WITH 13 WATT CFL

		Participant Cost Test ($)	Utility Cost Test ($)	Rate Impact Test ($)	Total Resource Cost Test ($)	Societal Cost Test ($)
Benefits:	- Utility avoided generating capacity cost		8	8	8	8
	- Utility avoided T&D capacity cost		10	10	10	10
	- Utility avoided energy supply cost		13	13	13	13
	- Reduction in participants' bills	22				
	- Avoided cost of incandescent halogen lamps	3			3	3
	- Incentive rebate to participants	0				
	- Value of avoided CO2 emissions					3
	Total	25	31	31	35	37
Costs:	- Utility DSM program admin. costs		0	0	0	0
	- Utility DSM program rebate costs		0	0		
	- Revenue reduction to utility			19		
	- Participant's incremental capital cost	1			1	1
	- Cost to replace lost space heating	12			12	12
	Total	13	0	19	13	13
	Net benefit (cost)	12	31	12	22	24
	Benefit/cost ratio	1.95	??	1.63	2.67	2.88

Inputs and Assumptions

Equipment life (6,000 hours effective life)	years	8.2	
Escalation rate	%	2.0	
Present value factor for 8.2 yrs at 7.0 % discount rate is		6.6	or escalating items
		6.1	for non-escalating items
Estimated annual average incremental T&D losses	%	11.5	
Estimated incremental T&D losses at system peak	%	15.7	
Utility avoided generating capacity cost:			
- participant load reduction at time of system peak	kW	0.010	
- cost of generating capacity	$/kW - year	100	(purchases on the margin)
- present value is	$	8	(+ 15 % planning reserve)
Utility avoided T&D capacity cost:			
- demand related T&D capacity cost	$/kW - year	160	(adjusted for losses)
- present value is	$	10	
Utility avoided energy supply cost:			
- annual energy saving by participant	kWh	22	
- price of purchased energy	$/kWh	0.08	
- present value is	$	13	
Reduction in participant's bills:			
- retail energy charge for electricity	$/kWh	0.1316	Residential first block
- present value is	$	22	(HST at 14 % applied)
Rebate to participant:			
- higher price for bare CFL ($3.50 - $2.50)	$	1.00	
- portion rebated to participant	%	-	
- participants rebate	$	-	
Cost to replace lost space heating:			
- furnace oil equivalent of annual energy savings	litres	3	(1 litre = 8.5 kWh)
- portion of energy savings that provided space heating	%	67	(8 month htg season)
- assumed furnace oil price	$/litre	1.00	
- present value of cost for additional furnace oil	$	12	(GST at 5 % applied)
Benefit of avoided CO2 emissions:			
- assumed CO2 emissions rate	kg/kWh	0.60	
- avoided annual CO2 emissions due to 13 W CFL	kg	15	
- annual CO2 emissions from replacement space htg	kg	5	
- assumed price of CO2 emissions	$/tonne	40	
- present value is	$	3	

Annual saving with bare CFL is	22	kWh	((43 W - 13 W) x 2 h/day x 365 days)
Reduction in customer load for one unit is	0.030	kW	(43 W - 13 W)
Assume average reduction at system peak is	0.010	kW	(33 % on at time of system peak)

Appendix 3

BENEFIT COST ANALYSIS OF REBATE FOR REPLACING 43 WATT INCANDESCENT HALOGEN WITH 11 WATT LED

		Participant Cost Test ($)	Utility Cost Test ($)	Rate Impact Test ($)	Total Resource Cost Test ($)	Societal Cost Test ($)
Benefits:	- Utility avoided generating capacity cost		10	10	10	10
	- Utility avoided T&D capacity cost		12	12	12	12
	- Utility avoided energy supply cost		16	16	16	16
	- Reduction in participants' bills	27				
	- Avoided cost of incandescent halogen lamps	4			4	4
	- Incentive rebate to participants	5				
	- Value of avoided CO2 emissions					3
	Total	36	39	39	43	46
Costs:	- Utility DSM program admin. costs		5	5	5	5
	- Utility DSM program rebate costs		5	5		
	- Revenue reduction to utility			24		
	- Participant’s incremental capital cost	8			8	8
	- Cost to replace lost space heating	15			15	15
	Total	23	10	34	28	28
	Net benefit (cost)	13	29	5	15	18
	Benefit/cost ratio	1.58	3.86	1.14	1.53	1.65

Inputs and Assumptions

Advance replacement of incandescent with LED by	years	10.0	
Escalation rate	%	2.0	
Present value factor for 10 yrs at 7.0 % discount rate is		7.8	or escalating items
		7.0	for non-escalating items
Estimated annual average incremental T&D losses	%	11.5	
Estimated incremental T&D losses at system peak	%	15.7	
Utility avoided generating capacity cost:			
- participant load reduction at time of system peak	kW	0.011	
- cost of generating capacity	$/kW - year	100	(purchases on the margin)
- present value is	$	10	(+15% planning reserve)
Utility avoided T&D capacity cost:			
- demand related T&D capacity cost	$/kW - year	160	(adjusted for losses)
- present value is	$	12	
Utility avoided energy supply cost:			
- annual energy saving by participant	kWh	23	
- price of purchased energy	$/kWh	0.08	
- present value is	$	16	
Reduction in participant's bills:			
- retail energy charge for electricity	$/kWh	0.1316	Residential first block
- present value is	$	27	(HST at 14 % applied)
Rebate to participant:			
- higher price for LED ($10.50 - $2.50)	$	8.00	
- portion rebated to participant	%	62.5	
- participants rebate	$	5.00	
Cost to replace lost space heating:			
- furnace oil equivalent of annual energy savings	litres	3	(1 litre = 8.5 kWh)
- portion of energy savings that provided space heating	%	67	(8 month htg season)
- assumed furnace oil price	$/litre	1.00	
- present value of cost for additional furnace oil	$	15	(GST at 5 % applied)
Benefit of avoided CO2 emissions:			
- assumed CO2 emissions rate	kg/kWh	0.60	
- avoided annual CO2 emissions due to 13 W CFL	kg	16	
- annual CO2 emissions from replacement space htg	kg	5	
- assumed price of CO2 emissions	$/tonne	40	
- present value is	$	3	

Annual saving with LED is	23	kWh	((43 W - 11 W) x 2 h/day x 365 days)
Reduction in customer load for one unit is	0.032	kW	(43 W - 11 W)
Assume average reduction at system peak is	0.011	kW	(33 % on at time of system peak)

Appendix 4

BENEFIT COST ANALYSIS OF REBATE FOR REPLACING 13 WATT CFL WITH 11 WATT LED

		Participant Cost Test ($)	Utility Cost Test ($)	Rate Impact Test ($)	Total Resource Cost Test ($)	Societal Cost Test ($)
Benefits:	- Utility avoided generating capacity cost		1	1	1	1
	- Utility avoided T&D capacity cost		1	1	1	1
	- Utility avoided energy supply cost		1	1	1	1
	- Reduction in participants' bills	2				
	- Avoided cost of CFL lamps	3			3	3
	- Incentive rebate to participants	5				
	- Value of avoided CO2 emissions					0
	Total	10	2	2	5	6
Costs:	- Utility DSM program admin. costs		5	5	5	5
	- Utility DSM program rebate costs		5	5		
	- Revenue reduction to utility			1		
	- Participant's incremental capital cost	7			7	7
	- Cost to replace lost space heating	1			1	1
	Total	8	10	11	13	13
	Net benefit (cost)	2	(8)	(9)	(8)	(7)
	Benefit/cost ratio	1.21	0.24	0.21	0.41	0.43

Inputs and Assumptions

Advance replacement of CFL with LED by	years	10.0	
Escalation rate	%	2.0	
Present value factor for 10 yrs at 7.0 % discount rate is		7.8	or escalating items
		7.0	for non-escalating items
Estimated annual average incremental T&D losses	%	11.5	
Estimated incremental T&D losses at system peak	%	15.7	
Utility avoided generating capacity cost:			
- participant load reduction at time of system peak	kW	0.001	
- cost of generating capacity	$/kW - year	100	(purchases on the margin)
- present value is	$	1	(+15% planning reserve)
Utility avoided T&D capacity cost:			
- demand related T&D capacity cost	$/kW - year	160	(adjusted for losses)
- present value is	$	1	
Utility avoided energy supply cost:			
- annual energy saving by participant	kWh	1	
- price of purchased energy	$/kWh	0.08	
- present value is	$	1	
Reduction in participant's bills:			
- retail energy charge for electricity	$/kWh	0.1316	Residential first block
- present value is	$	2	(HST at 14 % applied)
Rebate to participant:			
- higher price for LED ($10.50 - $3.50)	$	7.00	
- portion rebated to participant	%	71.4	
- participants rebate	$	5.00	
Cost to replace lost space heating:			
- furnace oil equivalent of annual energy savings	litres	0	(1 litre = 8.5 kWh)
- portion of energy savings that provided space heating	%	67	(8 month htg season)
- assumed furnace oil price	$/litre	1.00	
- present value of cost for additional furnace oil	$	1	(GST at 5 % applied)
Benefit of avoided CO2 emissions:			
- assumed CO2 emissions rate	kg/kWh	0.60	
- avoided annual CO2 emissions due to 13 W CFL	kg	1	
- annual CO2 emissions from replacement space htg	kg	0	
- assumed price of CO2 emissions	$/tonne	40	
- present value is	$	0	

Annual saving with LED is	1	kWh	((13 W - 11 W) x 2 h/day x 365 days)
Reduction in customer load for one unit is	0.002	kW	(13 W - 11 W)
Assume average reduction at system peak is	0.001	kW	(33 % on at time of system peak)

Appendix 5

BENEFIT COST ANALYSIS OF REBATES FOR REPLACING ONE 43 WATT INCANDESCENT HALOGEN AND ONE 13 WATT CFL WITH TWO 11 WATT LEDS

		Participant Cost Test ($)	Utility Cost Test ($)	Rate Impact Test ($)	Total Resource Cost Test ($)	Societal Cost Test ($)
Benefits:	- Utility avoided generating capacity cost		5	5	5	5
	- Utility avoided T&D capacity cost		6	6	6	6
	- Utility avoided energy supply cost		9	9	9	9
	- Reduction in participants' bills	14				
	- Avoided cost of incandescent halogen and CFL lamps	3			3	3
	- Incentive rebate to participants	5				
	- Value of avoided CO2 emissions					2
	Total	23	21	21	24	26
Costs:	- Utility DSM program admin. costs		5	5	5	5
	- Utility DSM program rebate costs		5	5		
	- Revenue reduction to utility			13		
	- Participant's incremental capital cost	8			8	8
	- Cost to replace lost space heating	8			8	8
	Total	15	10	23	20	20
	Net benefit (cost)	8	11	(2)	4	5
	Benefit/cost ratio	1.49	2.05	0.90	1.17	1.26

The dollar amounts in the above table are the average of the corresponding dollar amount in Appendix 3 (11 Watt LED replacing 43 Watt incandescent halogen) and Appendix 4 (11 Watt LED replacing 13 Watt CFL).

Appendix 6

BENEFIT COST ANALYSIS OF REBATE FOR REPLACING 65 WATT BR30 INCANDESCENT REFLECTOR WITH 16 WATT CFL BR30 REFLECTOR

		Participant Cost Test ($)	Utility Cost Test ($)	Rate Impact Test ($)	Total Resource Cost Test ($)	Societal Cost Test ($)
Benefits:	- Utility avoided generating capacity cost		14	14	14	14
	- Utility avoided T&D capacity cost		16	16	16	16
	- Utility avoided energy supply cost		21	21	21	21
	- Reduction in participants' bills	36				
	- Avoided cost of BR30 incandescent lamps	7			7	7
	- Incentive rebate to participants	2				
	- Value of avoided CO2 emissions					4
	Total	45	51	51	58	63
Costs:	- Utility DSM program admin. costs		5	5	5	5
	- Utility DSM program rebate costs		2	2		
	- Revenue reduction to utility			31		
	- Participant's incremental capital cost	4			4	4
	- Cost to replace lost space heating	20			20	20
	Total	24	7	38	29	29
	Net benefit (cost)	21	44	13	30	34
	Benefit/cost ratio	1.90	7.28	1.33	2.04	2.19

Inputs and Assumptions

Equipment life (6,000 hours effective life)	years	8.2	
Escalation rate	%	2.0	
Present value factor for 8.2 yrs at 7.0 % discount rate is		6.6	or escalating items
		6.1	for non-escalating items
Estimated annual average incremental T&D losses	%	11.5	
Estimated incremental T&D losses at system peak	%	15.7	
Utility avoided generating capacity cost:			
- participant load reduction at time of system peak	kW	0.016	
- cost of generating capacity	$/kW - year	100	(purchases on the margin)
- present value is	$	14	(+15% planning reserve)
Utility avoided T&D capacity cost:			
- demand related T&D capacity cost	$/kW - year	160	(adjusted for losses)
- present value is	$	16	
Utility avoided energy supply cost:			
- annual energy saving by participant	kWh	36	
- price of purchased energy	$/kWh	0.08	
- present value is	$	21	
Reduction in participant's bills:			
- retail energy charge for electricity	$/kWh	0.1316	Residential first block
- present value is	$	36	(HST at 14 % applied)
Rebate to participant:			
- higher price for BR30 CFL ($7.50 - $3.50)	$	4.00	
- portion rebated to participant	%	50	
- participants rebate	$	2.00	
Cost to replace lost space heating:			
- furnace oil equivalent of annual energy savings	litres	4	(1 litre = 8.5 kWh)
- portion of energy savings that provided space heating	%	67	(8 month htg season)
- assumed furnace oil price	$/litre	1.00	
- present value of cost for additional furnace oil	$	20	(GST at 5 % applied)
Benefit of avoided CO2 emissions:			
- assumed CO2 emissions rate	kg/kWh	0.60	
- avoided annual CO2 emissions due to BR30 CFL	kg	24	
- annual CO2 emissions from replacement space htg	kg	7	
- assumed price of CO2 emissions	$/tonne	40	
- present value is	$	4	

Annual saving with BR30 CFL is	36	kWh	((65 W - 13 W) x 2 h/day x 365 days)
Reduction in customer load for one unit is	0.049	kW	(65 W - 16 W)
Assume average reduction at system peak is	0.016	kW	(33 % on at time of system peak)

Appendix 7

BENEFIT COST ANALYSIS OF REBATE FOR REPLACING 65 WATT BR30 INCANDESCENT REFLECTOR WITH 13 WATT LED BR30 REFLECTOR

		Participant Cost Test ($)	Utility Cost Test ($)	Rate Impact Test ($)	Total Resource Cost Test ($)	Societal Cost Test ($)
Benefits:	- Utility avoided generating capacity cost		17	17	17	17
	- Utility avoided T&D capacity cost		19	19	19	19
	- Utility avoided energy supply cost		27	27	27	27
	- Reduction in participants' bills	44				
	- Avoided cost of BR30 incandescent lamps	9			9	9
	- Incentive rebate to participants	5				
	- Value of avoided CO2 emissions					6
	Total	58	63	63	71	77
Costs:	- Utility DSM program admin. costs		5	5	5	5
	- Utility DSM program rebate costs		5	5		
	- Revenue reduction to utility			39		
	- Participant’s incremental capital cost	14			14	14
	- Cost to replace lost space heating	24			24	24
	Total	38	10	49	43	43
	Net benefit (cost)	20	53	14	29	34
	Benefit/cost ratio	1.53	6.27	1.29	1.67	1.80

<u>Inputs and Assumptions</u>

Advance replacement of incandescent with LED by	years	10	
Escalation rate	%	2.0	
Present value factor for 10 yrs at 7.0 % discount rate is		7.8	or escalating items
		7.0	for non-escalating items
Estimated annual average incremental T&D losses	%	11.5	
Estimated incremental T&D losses at system peak	%	15.7	
Utility avoided generating capacity cost:			
- participant load reduction at time of system peak	kW	0.017	
- cost of generating capacity	$/kW - year	100	(purchases on the margin)
- present value is	$	17	(+15% planning reserve)
Utility avoided T&D capacity cost:			
- demand related T&D capacity cost	$/kW - year	160	(adjusted for losses)
- present value is	$	19	
Utility avoided energy supply cost:			
- annual energy saving by participant	kWh	38	
- price of purchased energy	$/kWh	0.08	
- present value is	$	27	
Reduction in participant's bills:			
- retail energy charge for electricity	$/kWh	0.1316	Residential first block
- present value is	$	44	(HST at 14 % applied)
Rebate to participant:			
- higher price for LED reflector light ($17.00 - $3.50)	$	13.50	
- portion rebated to participant	%	37.0	
- participants rebate	$	5.00	
Cost to replace lost space heating:			
- furnace oil equivalent of annual energy savings	litres	4	(1 litre = 8.5 kWh)
- portion of energy savings that provided space heating	%	67	(8 month htg season)
- assumed furnace oil price	$/litre	1.00	
- present value of cost for additional furnace oil	$	24	(GST at 5 % applied)
Benefit of avoided CO2 emissions:			
- assumed CO2 emissions rate	kg/kWh	0.60	
- avoided annual CO2 emissions due to LED pot light	kg	26	
- annual CO2 emissions from replacement space htg	kg	8	
- assumed price of CO2 emissions	$/tonne	40	
- present value is	$	6	

Annual saving with LED reflector light is	38	kWh	((65 W - 13 W) x 2 h/day x 365 days)
Reduction in customer load for one unit is	0.052	kW	(65 W - 13 W)
Assume average reduction at system peak is	0.017	kW	(33 % on at time of system peak)

Appendix 8

BENEFIT COST ANALYSIS OF REBATE FOR REPLACING 16 WATT CFL BR30 REFLECTOR WITH 13 WATT LED BR30 REFLECTOR

		Participant Cost Test ($)	Utility Cost Test ($)	Rate Impact Test ($)	Total Resource Cost Test ($)	Societal Cost Test ($)
Benefits:	- Utility avoided generating capacity cost		1	1	1	1
	- Utility avoided T&D capacity cost		1	1	1	1
	- Utility avoided energy supply cost		2	2	2	2
	- Reduction in participants' bills	3				
	- Avoided cost of BR30 CFLs	6			6	6
	- Incentive rebate to participants	5				
	- Value of avoided CO2 emissions					0
	Subtotal	14	4	4	10	10
Costs:	- Utility DSM program admin. costs		5	5	5	5
	- Utility DSM program rebate costs		5	5		
	- Revenue reduction to utility			2		
	- Participant’s incremental capital cost	10			10	10
	- Cost to replace lost space heating	1			1	1
	Subtotal	11	10	12	16	16
	Net benefit (cost)	3	(6)	(9)	(6)	(6)
	Benefit/cost ratio	1.26	0.36	0.30	0.62	0.64

Inputs and Assumptions

Advance replacement of incandescent with LED by	years	10	
Escalation rate	%	2.0	
Present value factor for 10 yrs at 7.0 % discount rate is		7.8	or escalating items
		7.0	for non-escalating items
Estimated annual average incremental T&D losses	%	11.5	
Estimated incremental T&D losses at system peak	%	15.7	
Utility avoided generating capacity cost:			
- participant load reduction at time of system peak	kW	0.001	
- cost of generating capacity	$/kW - year	100	(purchases on the margin)
- present value is	$	1	(+15% planning reserve)
Utility avoided T&D capacity cost:			
- demand related T&D capacity cost	$/kW - year	160	(adjusted for losses)
- present value is	$	1	
Utility avoided energy supply cost:			
- annual energy saving by participant	kWh	2	
- price of purchased energy	$/kWh	0.08	
- present value is	$	2	
Reduction in participant's bills:			
- retail energy charge for electricity	$/kWh	0.1316	Residential first block
- present value is	$	3	(HST at 14 % applied)
Rebate to participant:			
- higher price for LED reflector light ($17.00 - $7.50)	$	9.50	
- portion rebated to participant	%	52.6	
- customer rebate	$	5.00	
Cost to replace lost space heating:			
- furnace oil equivalent of annual energy savings	litres	0	(1 litre = 8.5 kWh)
- portion of energy savings that provided space heating	%	67	(8 month htg season)
- assumed furnace oil price	$/litre	1.00	
- present value of cost for additional furnace oil	$	1	(GST at 5 % applied)
Benefit of avoided CO2 emissions:			
- assumed CO2 emissions rate	kg/kWh	0.60	
- avoided annual CO2 emissions due to LED pot light	kg	1	
- annual CO2 emissions from replacement space htg	kg	0	
- assumed price of CO2 emissions	$/tonne	40	
- present value is	$	0	

Annual saving with LED reflector light is	2	kWh	((16 W - 13 W) x 2 h/day x 365 days)
Reduction in customer load for one unit is	0.003	kW	(16 W - 13 W)
Assume average reduction at system peak is	0.001	kW	(33 % on at time of system peak)

Appendix 9
BENEFIT COST ANALYSIS OF REBATES FOR REPLACING ONE 65 WATT BR30 INCANDESCENT REFLECTOR AND ONE 16 WATT CFL BR30 REFLECTOR WITH TWO 13 WATT LED BR30 REFLECTORS

		Participant Cost Test ($)	Utility Cost Test ($)	Rate Impact Test ($)	Total Resource Cost Test ($)	Societal Cost Test ($)
Benefits:	- Utility avoided generating capacity cost		9	9	9	9
	- Utility avoided T&D capacity cost		10	10	10	10
	- Utility avoided energy supply cost		14	14	14	14
	- Reduction in participants' bills	23				
	- Avoided cost of incandescent halogen and CFL lamps	7			7	7
	- Incentive rebate to participants	5				
	- Value of avoided CO2 emissions					3
	Total	36	33	33	41	44
Costs:	- Utility DSM program admin. costs		5	5	5	5
	- Utility DSM program rebate costs		5	5		
	- Revenue reduction to utility			20		
	- Participant’s incremental capital cost	12			12	12
	- Cost to replace lost space heating	13			13	13
	Total	24	10	30	29	29
	Net benefit (cost)	11	23	3	11	14
	Benefit/cost ratio	1.47	3.32	1.09	1.38	1.48

The dollar amounts in the above table are the average of the corresponding dollar amount in Appendix 7 (13 Watt LED replacing 65 Watt incandescent reflector) and Appendix 8 (13 Watt LED replacing 16 Watt CFL).

Appendix 10
BENEFIT COST ANALYSIS OF ENERGY STAR REFRIGERATOR REBATE

Free riders have been taken into account		Participant Cost Test ($)	Utility Cost Test ($)	Rate Impact Test ($)	Total Resource Cost Test ($)	Societal Cost Test ($)
Benefits:	- Utility avoided generating capacity cost		8	8	8	8
	- Utility avoided T&D capacity cost		9	9	9	9
	- Utility avoided energy supply cost		43	43	43	43
	- Reduction in participants' bills	71				
	- Incentive rebate to participants	30				
	- Value of avoided CO2 emissions					9
	Total	101	60	60	60	68
Costs:	- Utility DSM program admin. costs		10	10	10	10
	- Utility DSM program rebate costs		30	30		
	- Revenue reduction to utility			62		
	- Participant's incremental capital cost	50			50	50
	- Cost to replace lost space heating	39			39	39
	Total	89	40	102	99	99
	Net benefit (cost)	12	20	(42)	(39)	(30)
	Benefit/cost ratio	1.13	1.49	0.58	0.60	0.69

Inputs and Assumptions

Equipment life	years	18	
Escalation rate	%	2.0	
Present value factor for 18 yrs at 7.0 % discount rate is		11.8	or escalating items
		10.1	for non-escalating items
Estimated annual average incremental T&D losses	%	11.5	
Estimated incremental T&D losses at system peak	%	15.7	
Utility avoided generating capacity cost:			
- participant load reduction at time of system peak	kW	0.057	
- cost of generating capacity	$/kW - year	100	(purchases on the margin)
- present value is	$	8	(+15% planning reserve)
Utility avoided T&D capacity cost:			
- demand related T&D capacity cost	$/kW - year	160	(adjusted for losses)
- present value is	$	9	
Utility avoided energy supply cost:			
- annual energy saving by participant	kWh	40	
- price of purchased energy	$/kWh	0.08	
- present value is	$	43	
Reduction in participant's bills:			
- retail energy charge for electricity	$/kWh	0.1316	Residential first block
- present value is	$	71	(HST at 14 % applied)
Rebate to participant:			
- higher price for ENERGY STAR refrigerator	$	50.00	
- portion rebated to participant	%	60	
- participant rebate	$	30.00	
Cost to replace lost space heating:			
- furnace oil equivalent of annual energy savings	litres	5	(1 litre = 8.5 kWh)
- portion of energy savings that provided space heating	%	67	(8 month htg season)
- assumed furnace oil price	$/litre	1.00	
- present value of cost for additional furnace oil	$	39	(GST at 5 % applied)
Benefit of avoided CO2 emissions:			
- assumed CO2 emissions rate	kg/kWh	0.60	indicative value
- avoided annual CO2 emissions due to refrigerator	kg	27	
- annual CO2 emissions from replacement space htg	kg	8	
- assumed price of CO2 emissions	$/tonne	40	
- present value is	$	9	

Annual saving with Energy Star refrigerator is	40	kWh	(difference for 16.5 – 18.4 cu ft units)
Average reduction in customer load is	0.046	kW	(40 kWh/8,760 hours in year)
Assume average reduction at system peak is	0.057	kW	(1.25 times average load)

Appendix 11

BENEFIT COST ANALYSIS OF ENERGY STAR CLOTHES WASHER REBATE
(ENERGY STAR front loading versus non-ENERGY STAR front loading)

Free riders have been taken into account		Participant Cost Test ($)	Utility Cost Test ($)	Rate Impact Test ($)	Total Resource Cost Test ($)	Societal Cost Test ($)
Benefits:	- Utility avoided generating capacity cost		13	13	13	13
	- Utility avoided T&D capacity cost		15	15	15	15
	- Utility avoided energy supply cost		64	64	64	64
	- Reduction in participant electric bills	106				
	- Reduction in participant fce oil bills	33			33	33
	- Incentive rebate to participants	50				
	- Avoided CO2 emissions: electricity					19
	- Avoided CO2 emissions: furnace oil					3
	Total	189	92	92	126	148
Costs:	- Utility DSM program admin. costs		10	10	10	10
	- Utility DSM program rebate costs		50	50		
	- Revenue reduction to utility			93		
	- Participants incremental capital cost	125			125	125
	- Cost to replace lost space heating	0			0	0
	Total	125	60	153	135	135
	Net benefit (cost)	64	32	(61)	(9)	13
	Benefit/cost ratio	1.51	1.54	0.60	0.93	1.10

Inputs and Assumptions

Equipment life	years	14	
Escalation rate	%	2.0	
Present value factor for 14 yrs at 7.0 % discount rate is		10.0	or escalating items
		8.7	for non-escalating items
Estimated annual average incremental T&D losses	%	11.5	
Estimated incremental T&D losses at system peak	%	15.7	
Utility avoided generating capacity cost:			
- participant load reduction at time of system peak	kW	0.011	
- cost of generating capacity	$/kW - year	100	(purchases on the margin)
- present value is	$	13	(+15% planning reserve)
Utility avoided T&D capacity cost:			
- demand related T&D capacity cost	$/kW - year	160	(adjusted for losses)
- present value is	$	15	
Utility avoided energy supply cost:			
- annual energy saving by participants	kWh	71	
- price of purchased energy	$/kWh	0.08	
- present value is	$	64	
Reduction in participant's electricity bill:			
- retail energy charge for electricity	$/kWh	0.1316	Residential first block
- present value is	$	106	(HST at 14 % applied)
Rebate to participant:			
- higher price for ENERGY STAR clothes washer	$	125.00	
- portion rebated to participants	%	40	
- participants rebate	$	50.00	
Reduction in participant’s furnace oil bill:			
- annual reduction in furnace oil for water heating	litres	3	(1 litre = 8.5 kWh)
- assumed furnace oil price	$/litre	1.00	
- present value of reduction in furnace oil	$	33	(GST at 5 % applied)
Benefit of avoided CO2 emissions:			
- assumed CO2 emissions rate for electricity	kg/kWh	0.60	
- assumed price of CO2 emissions	$/tonne	40	
- present value for reduction in electricity is	$	19	
- present value for reduction in furnace oil is	$	3	

Annual saving with ENERGY STAR unit:	12	kWh for mechanical (25% of EnerGuide usage)
	36	kWh for water heating (75% of EnerGuide usage)
	50	kWh for dryer energy
Average reduction in customer load is	0.0081	kW (25% of water heating is by electricity)
Assume average reduction at system peak is	0.0109	kW (1.35 times average load)

Appendix 12
BENEFIT COST ANALYSIS OF A REFRIGERATOR ROUNDUP PROGRAM

		Participant Cost Test ($)	Utility Cost Test ($)	Rate Impact Test ($)	Total Resource Cost Test ($)	Societal Cost Test ($)
Benefits:	- Utility avoided generating capacity cost		53	53	53	53
	- Utility avoided T&D capacity cost		63	63	63	63
	- Utility avoided energy supply cost		342	342	342	342
	- Reduction in participant's bills	567				
	- Incentive rebate to participants	35				
	- Value of avoided CO2 emissions					71
	Total	602	458	458	458	529
Costs:	- Utility DSM program admin. costs		287	287	287	287
	- Utility DSM program rebate costs		35	35		
	- Revenue reduction to utility			498		
	- Participant's incremental capital cost	0			0	0
	- Cost to replace lost space heating	311			311	311
	Total	311	322	820	598	598
	Net benefit (cost)	291	136	(362)	(141)	(69)
	Benefit/cost ratio	1.93	1.42	0.56	0.76	0.88

Inputs and Assumptions

Remaining equipment life	years	10	
Escalation rate	%	2.0	
Present value factor for 10 yrs at 7.0 % discount rate is		7.8	or escalating items
		7.0	for non-escalating items
Estimated annual average incremental T&D losses	%	11.5	
Estimated incremental T&D losses at system peak	%	15.7	
Utility avoided generating capacity cost:			
- participant load reduction at time of system peak	kW	0.056	
- cost of generating capacity	$/kW - year	100	(purchases on the margin)
- present value is	$	53	(+15% planning reserve)
Utility avoided T&D capacity cost:			
- demand related T&D capacity cost	$/kW - year	160	(adjusted for losses)
- present value is	$	63	
Utility avoided energy supply cost:			
- annual energy saving by participants	kWh	488	
- price of purchased energy	$/kWh	0.08	
- present value is	$	342	
Reduction in participant's electric bills:			
- retail energy charge for electricity	$/kWh	0.1316	Residential first block
- present value is	$	567	(HST at 14 % applied)
Rebate to participants	$	35.00	
Cost to replace lost space heating:			
- furnace oil equivalent of annual energy savings	litres	57	(1 litre = 8.5 kWh)
- portion of energy savings that provided space heating	%	67	(8 month htg season)
- assumed furnace oil price	$/litre	1.00	
- present value of cost for additional furnace oil	$	311	(GST at 5% applied)
Benefit of avoided CO2 emissions:			
- assumed CO2 emissions rate	kg/kWh	0.60	
- avoided annual CO2 emissions due to refrigerator	kg	331	
- annual CO2 emissions from replacement space htg	kg	101	
- assumed price of CO2 emissions	$/tonne	40	
- present value is		71	

Annual usage by second refrigerator is	650	kWh (assume 2004 vintage)
Potential ave. reduction in customer load is	0.074	kW (650 kWh/8,760 hours in year)
Percentage assumed to be plugged in	75	%
Assume average reduction at system peak is	0.056	kW

Appendix 13
BENEFIT COST ANALYSIS OF MATCHING GRANT FOR COLD CLIMATE HEAT PUMP (OPERATION DOWN TO -25C) IN HOMES WITH ELECTRIC RESISTANCE HEATING

OEE grant is factored in – the assumption is that the OEE grant of $425 plus a matching grant from Maritime Electric is needed to increase the number of "most efficient" units purchased.		Participant Cost Test ($)	Utility Cost Test ($)	Rate Impact Test ($)	Total Resource Cost Test ($)	Societal Cost Test ($)
Benefits:	- Reduction in utility generating capacity purchase		2,031	2,031	2,031	2,031
	- Reduction in utility demand related T&D capacity cost		2,383	2,383	2,383	2,383
	- Reduction in utility energy supply cost		341	341	341	341
	- Net Reduction in participant's electricity bill	566				
	- OEE grant for "most efficient" heat pump	425				
	- Marching grant from utility	425				
	- Value of avoided CO2 emissions					102
	Total	1,416	4,755	4,755	4,755	4,857
Costs:	- Utility share of OEE admin. costs		338	338	150	150
	- OEE share of admin. costs				150	150
	- Matching grant from utility		956	956		
	- Revenue decrease for utility			496		
	- Extra cost for "most efficient" heat pump	1,000			1,000	1,000
	Total	1,000	1,294	1,790	1,300	1,300
	Net benefit (cost)	416	3,461	2,965	3,455	3,557
	Benefit/cost ratio	1.42	3.68	2.66	3.66	3.74

Note: Under the Utility Cost test and the Rate Impact test the utility share of OEE admin costs and the matching grant from utility have been scaled up by 360/160 to account for free riders; i.e. currently 200 per year are incented by just the OEE grant, and the goal of the utility matching grant is to increase that number to 360.

Inputs and Assumptions

Mini-split heat pump life	years	15	
Escalation rate	%	2.0	
Present value factor for 15 yrs at 7.0 % discount rate is		10.4	or escalating items
		9.1	for non-escalating items
Estimated annual average incremental T&D losses	%	11.5	
Estimated incremental T&D losses at system peak	%	15.7	
Utility avoided generating capacity cost: (assumes not "most efficient" unit turns itself off at -15C)			
- electric resistance load displaced by heat pump at peak	kW	3.27	
- heat pump load at system peak	kW	1.64	assume COP of 2.0
- net reduction in heating load at system peak	kW	1.64	
- cost of generating capacity	$/kW - year	100	(purchases on the margin)
- present value is	$	2,031	(+15% planning reserve)
Utility avoided T&D capacity cost:			
- demand related T&D capacity cost	$/kW - year	160	(adjusted for losses)
- present value is	$	2,383	
Reduction in utility energy supply cost:			
- participant's usage below -14C for electric resistance	kWh	722	
- participant's usage below -14C for "most efficient" heat pump	kWh	361	Assume COP of 2.0
- net reduction in participant's electricity usage below -14C	kWh	361	
- energy supply cost	$/kWh	80	
- present value is	$	341	
Reduction in participant's electricity bill:			
- net reduction electricity usage below -14C	kWh	361	
- retail price for electricity	$/kW	0.1316	residential first block
- present value is	$	566	(HST at 14% applied)
Benefit of avoided CO2 emissions:			
- assumed CO2 emissions rate for electricity supply	kg/kWh	0.60	
- net reduction in annual CO2 emissions from electricity supply	tonne	0.24	
- assumed price of CO2 emissions	$/tonne	40	
- present value is	$	102	

Appendix 14
BENEFIT COST ANALYSIS OF INCENTIVE FOR THERMOSTAT CONTROL OF HEAT PUMP IN HOMES WITH OIL-FIRED HEATING

OEE grant is factored in – the assumption is that the homeowner has already chosen to purchase a "most efficient" unit based on just the OEE $425 grant.		Participant Cost Test ($)	Utility Cost Test ($)	Rate Impact Test ($)	Total Resource Cost Test ($)	Societal Cost Test ($)
Benefits:	- Reduction in utility generating capacity purchase		1,016	1,016	1,016	1,016
	- Reduction in utility demand related T&D capacity cost		1,191	1,191	1,191	1,191
	- Reduction in utility energy supply cost		341	341	341	341
	- Reduction in participant's electricity bill	566				
	- Annual credit on participant's electricity bill	911				
	- Value of avoided CO2 emissions					9
	Total	1,477	2,548	2,548	2,548	2,557
Costs:	- Utility share of OEE admin. costs		150	150		
	- Annual credit on participant's electricity bill		911	911		
	- Cost of thermostat controlled shutoff		500	500	500	50
	- Revenue decrease for utility			497		
	- Increase in participant furnace oil bill	933			933	933
	Total	933	1,561	2,058	1,433	1,433
	Net benefit (cost)	545	987	491	1,116	1,125
	Benefit/cost ratio	1.58	1.63	1.24	1.78	1.78

<u>Inputs and Assumptions</u>

Mini-split heat pump life	years	15	
Escalation rate	%	2.0	
Present value factor for 15 yrs at 7.0 % discount rate is		10.4	or escalating items
		9.1	for non-escalating items
Estimated annual average incremental T&D losses	%	11.5	
Estimated incremental T&D losses at system peak	%	15.7	
Utility avoided generating capacity cost:			
- net reduction in heating load at system peak	kW	0.82	50% for shut off at -15C
- cost of generating capacity	$/kW - year	100	(purchases on the margin)
- present value is	$	1,016	(+15% planning reserve)
Utility avoided T&D capacity cost:			
- demand related T&D capacity cost	$/kW - year	160	(adjusted for losses)
- present value is	$	1,191	
Reduction in utility energy supply cost:			
- reduction in participant's electricity usage below -14C	kWh	361	Assume COP of 2.0
- energy supply cost	$/kWh	80	
- present value is	$	341	
Reduction in participant's electricity bill:			
- electricity for heat pump below -14C	kWh	361	
- retail price for electricity	$/kW	0.1316	residential first block
- present value is	$	566	(HST at 14% applied)
Increase in participant's furnace oil bill:			
- increase in furnace oil used below -14C	litres	85	
- assumed furnace oil price	$/litre	1.00	
- present value of cost for additional furnace oil	$	933	(GST at 5% applied)
Annual credit on participant's electricity bill	$	100	
Benefit of avoided CO2 emissions:			
- assumed CO2 emissions rate for electricity supply	kg/kWh	0.60	indicative value
- reduction in annual CO2 emissions from electricity supply	tonne	0.24	
- annual CO2 emissions from increase in furnace oil	tonne	0.22	
- assumed price of CO2 emissions	$/tonne	40	
- present value is	$	9	

Appendix 15
SCHEULE OF PROPOSED YEARLY EXPENDITURES

			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	3033	2034
Annual number of units for each measure:																						
- LED lighting rebates (x 1,000)				185.6	185.6	185.6	185.6	185.6	8 over 5 years for each of 58,000 residential customers + an equal number of free riders													
- Heat pumps in electric resistance heated homes				360	360	360	360	360	10% of the estimated 3,600 units installed in 2013 assumed to be in electric resistance heated homes													
- Heat pumps in oil heated homes				100	810	810	810	810	90% of the 900 units rebated by OEE in 2013 assumed to be in oil heated homes													
Expenditures ($ x 1,000)																						
LED lighting rebate coupon:																						
- rebate coupons at $	5.00	each		928	928	928	928	928														
- administration costs	1.50	each		278	278	278	278	278														
- program development			50																			
			50	1,206	1,206	1,206	1,206	1,206														
Heat pumps in electric resistance heated homes:																						
- matching grant at $	425	each		153	153	153	153	153														
- MECL share of OEE admin $	150	each		54	54	54	54	54														
- program development			10																			
			10	207	207	207	207	207														
Thermostat-controlled heat pumps in oil heated home:																						
- electric bill credits at $	100	each/yr		10	91	172	253	334	334	334	334	334	334	334	334	334	334	334	324	243	162	81
- MECL share of OEE admin $	150	each		15	122	122	122	122														
- meter and thermostat at $	500	for both		50	405	405	405	405														
- program development			40																			
			40	75	618	699	780	861	334	334	334	334	334	334	334	334	334	334	324	243	162	81
Community outreach activities				168	168	168	168	168														
Total			100	1,656	2,198	2,279	2,360	2,441	334	334	334	334	334	334	334	34	334	334	324	243	162	81

Appendix 16
SCHEULE OF PROPOSED YEARLY RECOVERY OF COSTS THROUGH RATES

Assumed recovery period for each measure:		
- LED lighting rebates	10	years, based on assumed advancement of LED purchases by 10 years
- Heat pumps in electric resistance heated homes	15	years, based on assumed life of mini-split heat pump
- Heat pumps in oil heated homes	15	years, based on assumed life of mini-split heat pump (except for bill credits)
- Community outreach activities	1	year - fully recover in the year following when expense incurred

Recovery through rates ($ x 1,000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	3033	2034	2035
LED lighting rebate coupon:																				
- rebate coupon		93	186	278	371	464	464	464	464	464	464	371	278	186	93					
- couponing processing		28	56	84	111	139	139	139	139	139	139	111	84	56	28					
- program development		4	4	4	4	4	4	4	4	4	4	4	4	4	4					
		124	245	365	486	607	607	607	607	607	607	486	365	245	124					
Heat pumps in electric resistance heated homes:																				
- matching grant		10	20	31	41	51	51	51	51	51	51	51	51	51	51	51	41	31	20	10
- MECL share of OEE admin costs		4	7	11	14	18	18	18	18	18	18	18	18	18	18	18	14	11	7	4
- program development		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
		14	28	42	56	70	70	70	70	70	70	70	70	70	70	70	56	42	28	14
Thermostat-controlled heat pumps in oil heated home:																				
- electric bill credits		10	91	172	253	334	334	334	334	334	334	334	334	334	334	334	324	243	162	81
- MECL share of OEE admin costs		1	9	17	25	33	33	33	33	33	33	33	33	33	33	33	32	24	16	8
- cost of meters and thermostats		3	30	57	84	111	111	111	111	111	111	111	111	111	111	111	108	81	54	27
- program development		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
		16	133	249	365	481	481	481	481	481	481	481	481	481	481	481	467	350	234	118
Community outreach activities		168	168	168	168	168														
Total		322	573	824	1,074	1,325	1,157	1,157	1,157	1,157	1,157	1,036	916	795	675	550	522	392	262	133

CONSIDERATIONS FOR DSM PROGRAMMING FOR ELECTRICITY

Maritime Electric Company, Limited

April 25, 2017

Takeaways from Today's Presentation

- The Dunsky report's suggestion of a 2 % annual energy savings for electricity is an ambitious target
- The DSM industry has recently lowered the bar for what is deemed to be cost effective
- A 2 % annual savings for electricity would require an estimated increase in rates of 4.7 %

Outline of Presentation

- A look at Efficiency Nova Scotia (now Efficiency One) as a leader
- What does “cost effective” mean for DSM
- Estimated DSM program costs and implications for electricity rates

Efficiency Nova Scotia results

		2011	2012	2013	2014	2015	Ave 2016 to 2018
Expenditures	$ millions	35.8	43.6	43.4	38.7	32.0	34.1
Savings at the generator	GWh	141.8	158.1	163.2	151.9	137.9	135.3
Savings at the generator	MW	28.9	33.7	34.1	27.1	24.1	20.8
NSPI net gen. & purchases	TWh	11	11	11	11	11	11
Reduction in electricity use	%	1.3	1.4	1.5	1.4	1.3	1.2

Dunsky's suggested target of 2 % is ambitious

Efficiency NS (now Efficiency One) has the highest annual energy saving percentage in Canada

Next best in Canada is Ontario at 1.1 % (although Manitoba's target is 1.5 % for its new efficiency agency)

In the U.S. Vermont is the leader at 2.0 %

Next best in the U.S. is Massachusetts at 1.3 %

Breakdown of Efficiency NS savings for 2014

	Residential (GWh)	General Service (GWh)	Total (GWh)	Total (%)
Hot water	10.5	0.1	10.6	8.4
Space heating	14.9	16.8	31.8	25.2
Lighting	22.3	37.6	59.9	47.4
Appliances	5.4	-	5.4	4.3
Other	1.8	16.7	18.5	14.7
	55.0	71.2	126.2	100.0

Does not include 25.4 GWh for Home Energy Report

Benefit Cost analysis of ENERGY STAR Refrigerator Rebate

		Participant Cost test ($)	Program Admin. Cost test ($)	Rate Impact test ($)	Total Resource Cost test ($)	Societal Cost test ($)
Benefits:	- Utility avoided generating capacity cost		8	8	8	8
	- Utility avoided T&D capacity cost		9	9	9	9
	- Utility avoided energy supply cost		43	43	43	43
	- Reduction in participant's bills	71				
	- Incentive rebate to participant	30				
	- Value of avoided CO2 emissions					9
	total	101	60	60	60	68
Costs:	- DSM program administration costs		10	10	10	10
	- DSM program rebate costs		30	30		
	- Revenue reduction to utility			62		
	- Participant's incremental capital cost	50			50	50
	- Cost to replace lost space heating	39			39	39
	total	89	40	102	99	99
	Net benefit (cost)	12	20	(42)	(39)	(30)
	Benefit / cost ratio	1.13	1.49	0.58	0.60	0.69

The DSM Industry is moving to the PACT

- NB Power is using the Program Administrator Cost Test for their DSM programming development. They refer to Dunsky to support this.

- Efficiency One has requested to use the PACT for future DSM filings, also referencing Dunsky.

- Fortunately, the Dunsky report for PEI appears to recommend using the Societal Cost Test for deciding cost effectiveness.

Why the move to the PACT?

Reasons given by DSM proponents for using the Program Administrator Cost Test:

- It can be difficult to quantify participant non-energy benefits for the Total Resource Cost Test and the Societal Cost Test.

- Because the PACT compares the benefits to the utility to the costs the utility incurs to obtain those benefits, use of the PACT enables a direct comparison of DSM with supply-side options.

However, the PACT does not include all costs

- What is glossed over is that the ratepayer pays for 100% of supply options through rates, whereas he pays only a portion of DSM costs through rates. Therefore the PACT is not a balanced test for the ratepayer (and the ratepayer is the one who pays).

- The real reason for the use of the PACT is that in order to meet future DSM targets, more energy efficiency needs to be to deemed cost effective.

Pro rata estimated cost to achieve 2% energy savings

		Actual Efficiency Nova Scotia for 2014	Estimated for Maritime Electric load for 2018
Annual net gen. and purchases	GWh	11,129	1,300
Incremental annual energy saving	%	1.4	2.0
Incremental annual energy saving (at the generator)	GWh	151.9	26.0
Incremental annual capacity saving (at the generator)	MW	27.1	4.6
Annual DSM programming cost	$ millions	38.7	6.6

MECL Rate Impact Measure Test for first year (2018)

			($ x 1000)
Benefits:	- Avoided generating capacity cost	(4.6 MW)	529
	- Avoided T&D capacity cost	(4.6 MW)	736
	- Avoided energy supply cost	(26.0 GWh)	2,080
	total		3,345
Costs:	- Revenue reduction to utility:		
	from Residential sales	(12.2 GWh)	1,741
	from General Service sales	(10.8 GWh)	1,754
	- Amortization of DSM program costs	($ 6.6 million)	703
	total		4,198
	Net benefit (cost)		(853)
	Benefit / cost ratio		0.80

Recovery of DSM costs through rates

- MECL approved rates as per the General Rate Agreement provide for recovery of costs in 2017 and 2018 as proposed in MECL's 2015 DSM Application
- However, IRAC has approved spending for only MECL's customer outreach and education programs
- Monies collected for DSM but not spent would normally be returned to customers through RORA

Planned recovery of MECL DSM costs through rates

	Proposed MECL DSM program spending ($ x 1,000)	Allowance for recovery through rates: Customer outreach & education ($ x 1,000)	Allowance for recovery through rates: Annual amortizatn ($ x 1,000)	Allowance for recovery through rates: Subtotal ($ x 1,000)	Plus financing of deferred costs ($ x 1,000)	Total recovery through rates ($ x 1,000)
2016	1,756	-	-	-	55	55
2017	2,198	168	155	323	159	482
2018	2,279	168	406	573	265	838

Annual $ 167,500 for consumer outreach and education is expensed in following year.

Unused recovery of DSM costs through rates

	Expected MECL DSM program spending ($ x 1,000)	Recovery of MECL costs through rates: Customer outreach & education ($ x 1,000)	Annual amortizatn ($ x 1,000)	Subtotal ($ x 1,000)	Allowance for recovery through rates ($ x 1,000)	Returned to customers through RORA ($ x 1,000)
2016	144	-	-	-	55	55
2017	168	144	-	144	482	338
2018	100	168	-	168	838	671
2019	100	100	-	100	100	-

Assumes ongoing MECL annual spend of $ 100,000 for consumer outreach and education.

Recovery of DSM costs through rates for 2 % target
(With IRAC approval of Efficiency PEI costs and RORA)

	Estimated costs for 2 % annual energy savings		Unused existing	Required net increase in recovery through rates		
	Program costs ($ x 1,000)	Annual recovery ($ x 1,000)	allowance for recovery ($ x 1,000)	Annual increase ($ x 1,000)	Annual increase (%)	Cumulative increase (%)
2016			55			
2017			338			
2018	6,600		671			
2019	6,600	853	738	-	-	-
2020	6,600	1,706	738	19	0.01	0.01
2021	6,600	2,559	738	853	0.43	0.44
2022	6,600	3,412	738	853	0.43	0.86
2023	6,600	4,265	738	853	0.43	1.29
:	:	:	:	:	:	:
2031	6,600	11,089	738	853	0.43	4.70
2032	6,600	11,089	738	-	-	4.70

Forecast for EfficiencyPEI
2018-06-20

MARITIME ELECTRIC SALES AND LOAD FORECAST

(Impact of proposed EfficiencyPEI prgrams is included in forecast)

	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Fcast 2018	Fcast 2019	Fcast 2020	Fcast 2021	Fcast 2022	Fcast 2023
Energy Sales (GWh)										
Residential	541.4	568.1	563.4	577.0	583.1	587.6	592.7	601.2	613.1	626.9
General Service	386.6	389.0	386.8	384.9	385.4	388.8	389.9	390.5	391.5	391.9
Large Industrial	142.2	130.1	129.9	133.6	150.4	151.1	151.8	152.4	153.1	153.8
Small Industrial	88.9	93.1	100.1	104.6	93.4	94.2	94.5	94.6	94.8	94.9
Street lighting	6.2	6.0	5.8	5.5	5.3	5.0	4.8	4.5	4.3	4.1
Unmetered	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5
Total	1,167.7	1,188.7	1,188.4	1,208.0	1,220.0	1,229.1	1,236.1	1,245.7	1,259.3	1,274.1
Growth rate (%)										
Residential	5.27	4.93	(0.83)	2.41	1.06	0.77	0.87	1.43	1.98	2.25
General Service	1.79	0.62	(0.57)	(0.49)	0.13	0.88	0.28	0.15	0.26	0.10
Large Industrial	(0.84)	(8.51)	(0.15)	2.85	12.57	0.47	0.46	0.40	0.46	0.46
Small Industrial	9.89	4.72	7.52	4.50	(10.71)	0.86	0.32	0.11	0.21	0.11
Street lighting	0.65	(3.23)	(3.33)	(5.17)	(3.64)	(5.66)	(4.00)	(6.25)	(4.44)	(4.65)
Unmetered	1.35	-	-	-	-	-	-	4.17	-	-
Overall	3.60	1.80	(0.03)	1.65	0.99	0.75	0.57	0.78	1.09	1.18
Net Purchased and Produced (GWh)										
- Energy sales	1,167.7	1,188.7	1,188.4	1,208.0	1,220.0	1,229.1	1,236.1	1,245.7	1,259.3	1,274.1
- Company use	2.0	2.1	2.1	2.1	2.0	2.0	2.0	2.0	2.0	2.0
- System losses	87.8	88.4	90.4	88.0	92.0	92.7	93.2	93.9	94.9	96.1
Total	1,257.5	1,279.2	1,280.9	1,298.1	1,314.0	1,323.8	1,331.3	1,341.6	1,356.2	1,372.2

From: Younker, Robert
Sent: Wednesday, November 22, 2017 1:31 PM
To: 'Natasha Fillmore'; Cunniffe, John
Cc: alcrandlemire@gmail.com; Josh McLean; Mike Proud
Subject: RE: Looking for line loss figures

Hi Natasha,

We use the same T&D percentage loss values for residential and (distribution system) non-residential customers.
Annual average T&D losses are 7.0 %.
Incremental energy losses are estimated as 11.5 % (i.e. line losses associated with one more MWh of load during the year).
Incremental demand losses are estimated as 15.7 % (i.e. line losses associated with one more MW of load at system peak).

Bob

From: Natasha Fillmore [mailto:nfillmore@Efficiencyone.com]
Sent: Wednesday, November 22, 2017 12:39 PM
To: Younker, Robert; Cunniffe, John
Cc: alcrandlemire@gmail.com; Josh McLean; Mike Proud
Subject: Looking for line loss figures

Hello Bob,

We're in the final stages of preparing the draft DSM Plan for efficiencyPEI and are hoping for a bit more information from Maritime Electric. Specifically, we are looking for line losses for residential and non-residential clients for energy and demand (separately), so 4 numbers altogether. Would you be able to gather that information and send it along?

Your help would be greatly appreciated.

Best regards,
Natasha

Natasha Fillmore, BEP
Manager of Special Projects
Direct 902 470 3546

From: Younker, Robert [mailto:Younker@MaritimeElectric.com]
Sent: September-28-17 11:15 AM
To: Natasha Fillmore; Cunniffe, John
Cc: alcrandlemire@gmail.com; John Aguinaga; Chuck Faulkner; Josh McLean; Mike Proud
Subject: RE: Yesterday's meeting

Hi Natasha,

Please use 6.44 % as a WACC for Maritime Electric. This is based on 60% debt at 4.50% interest rate and 40% equity at 9.35% allowed rate of return, which I believe is representative for forward looking investments.

We did not talk about CO2 emissions. In Maritime Electric's 2015 DSM filing we used 0.6 kg / kWh as an indicative value for system energy purchases, which is in between natural gas fired combined cycle and coal fired generation. For your analysis I recommend that you use 0.3 kg / kWh, which I believe is more representative of NB Power's sources of supply for out-of-Province sales.

Bob

From: Natasha Fillmore [mailto:nfillmore@Efficiencyone.com]
Sent: Wednesday, September 27, 2017 12:43 PM
To: Younker, Robert; Cunniffe, John
Cc: alcrandlemire@gmail.com; John Aguinaga; Chuck Faulkner; Josh McLean; Mike Proud
Subject: Yesterday's meeting

Hello Bob and John,

Thank you again for meeting with us yesterday. It was very helpful to get your perspectives on DSM in PEI and to understand more about Maritime Electric's operations.

You mentioned that you could confirm your WACC for us. When you have a moment, could you send that to us? We should be able to pull most of the other information from you 2015 filing but will let you know if we have any other questions.

Best regards,
Natasha

Natasha Fillmore, BEP
Manager of Special Projects

EfficiencyOne Services

Direct +1 902 470 3546
Main +1 902 334 2066
Fax +1 902 470 3599

Email nfillmore@e1services.com
Internet www.e1services.com

Head Office: 230 Brownlow Avenue, Suite 300 | Dartmouth, Nova Scotia | Canada | B3B 0G5

All our energy
All the time

MARITIME ELECTRIC
A FORTIS COMPANY

August 28, 2018

RECEIVED
AUG 29 2018
The Island Regulatory and Appeals Commission

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

Dear Commissioners:

UE41400 - PEI Energy Corporation's
2018 – 2021 Demand Side Management Resource Plan

Please find attached Maritime Electric's comments on the PEI Energy Corporation's initial three year DSM Plan. Maritime Electric is generally supportive of the proposed plan but offers these comments for consideration when evaluating future plans.

Overall, the spending amount of the proposed plan appears to be of appropriate magnitude based on Maritime Electric's experience with cost effective testing in the Company's previous DSM filings.

Also, Maritime Electric fully supports a transition to LED lighting and the Company expects that a large portion of the proposed plan energy savings will come from incenting and encouraging a transition to LED lighting.

If you have any questions please do not hesitate to contact me at 902-629-3668.

Yours truly,

MARITIME ELECTRIC

Angus Orford

Angus S. Orford
Vice President, Corporate Planning
& Energy Supply

ASO15
Enclosure

180 Kent Street • PO Box 1328 • Charlottetown, PE C1A 7N2
telephone 1-800-670-1012 • fax 902-629-3665 • maritimeelectric.com

Maritime Electric Company, Limited
UE41400 - Comments on efficiencyPEI's initial three year DSM Plan
as filed by the PEI Energy Corporation

Introduction

Maritime Electric offers two comments on efficiencyPEI's application for approval of a three year Energy Efficiency & Demand Side Management Plan ("Plan"). These are:

1. efficiencyPEI is seeking approval to use the Program Administrator Cost test as the determinant of cost effectiveness. Maritime Electric's approach differs from the methodology of this request because the Program Administrator Cost test does not include all costs. Maritime Electric's view is that the Total Resource Cost test is the appropriate test to use for cost effectiveness testing.
2. efficiencyPEI is seeking approval to do cost effectiveness testing at the portfolio level. Maritime Electric's approach differs from the methodology of this request, and views cost effectiveness testing should be done at the individual measure level. Testing at the program or portfolio level (i.e. testing a group of measures as a bundle) can result in individual measures that are not cost effective being approved for implementation.

In providing these comments, Maritime Electric is not so much concerned with efficiencyPEI's current proposed Plan as with potential future plans. Maritime Electric is generally supportive of the current proposed Plan because:

- A target spending of $4 million annually appears to be appropriate. Based on the Company's experience with doing cost effectiveness testing for its 2010 and 2015 DSM filings, Maritime Electric believes that $4 million per year is in line with the level of spending that can be shown to be cost effective using the Total Resource Cost test at the individual measure level.
- LED lighting is transformational. Maritime Electric expects that a large portion of the current proposed Plan's electricity savings will come from incenting and encouraging a transition to LED lighting. Maritime Electric fully supports a transition to LED lighting – much of the Company's DSM efforts of the past ten years, both proposed and implemented, have been directed toward this goal.

Program Administer Cost test does not include all costs

efficiencyPEI is seeking approval to use the Program Administrator Cost ("PAC") test as the determinant of cost effectiveness. Maritime Electric's approach differs from the methodology of this request because the PAC test does not include all costs.

The table below shows a summary of Maritime Electric's cost effectiveness testing for a potential ENERGY STAR refrigerator rebate measure. The dollar amounts shown in the table are present value amounts. The full analysis was included in Maritime Electric's 2015 Demand Side Management and Energy Conservation Plan ("2015 DSM Plan") filing. The result for the

Total Resource Cost ("TRC") test shows this measure to be not cost effective (i.e. the benefit / cost ratio is less than 1.0) and thus Maritime Electric did not include it in its proposed 2015 DSM Plan.

2015 DSM Plan appendices				Appendix 10		
15-04-07		BENEFIT COST ANALYSIS OF ENERGY STAR REFRIGERATOR REBATE				
Free riders have not been taken into account		Participant Cost test ($)	Utility Cost test ($)	Rate Impact test ($)	Total Resource Cost test ($)	Societal Cost test ($)
Benefits:	- Utility avoided generating capacity cost		8	8	8	8
	- Utility avoided T&D capacity cost		9	9	9	9
	- Utility avoided energy supply cost		43	43	43	43
	- Reduction in participant's bills	71				
	- Incentive rebate to participant	30				
	- Value of avoided CO2 emissions					9
	total	101	60	60	60	68
Costs:	- Utility DSM program admin. costs		10	10	10	10
	- Utility DSM program rebate costs		30	30		
	- Revenue reduction to utility			62		
	- Participant's incremental capital cost	50			50	50
	- Cost to replace lost space heating	39			39	39
	total	89	40	102	99	99
	Net benefit (cost)	12	20	(42)	(39)	(30)
	Benefit / cost ratio	1.13	1.49	0.58	0.60	0.69

Note: In some cases the sum of columns and totals shown differ due to rounding.

The column for the TRC test shows three benefits:

- Utility avoided generating capacity cost of $8
- Utility avoided T&D capacity cost of $9
- Utility avoided energy supply cost of $43

The column for the TRC test also shows three costs:

- Utility (or Program Administrator) program administration costs of $10
- An incremental cost for the ENERGY STAR refrigerator of $50
- Cost of $39 to replace the lost space heating provided by a less efficient refrigerator (all the electricity used in a refrigerator ends up as heat inside the building envelope)

The column for the Utility Cost (or Program Administrator Cost) test shows the same three benefits as for the TRC test. For costs, the PAC test includes the program administration cost of $10, but it includes only a portion (the $30 rebate) of the extra $50 cost for the ENERGY STAR refrigerator, and it does not include any of the cost to replace lost space heating.

The fact that the PAC test does not include all the costs, as shown in the above example, results in the energy efficiency industry making statements like the one at the top of page 19 in efficiencyPEI's Evidence:

"The cost of promoting and incenting the adoption of energy efficiency is generally lower than the cost of electricity supply, transmission and distribution to customers. Levelized costs for electricity savings are typically 3-6 cents per kilowatt-hour for jurisdictions in the US Northeast and eastern Canada …".

In the context of the above ENERGY STAR refrigerator rebate example, the 3–6 cents per kilowatt-hour cost for energy efficiency would include the $10 for program administration and the $30 rebate – it would not include the remaining $20 of the extra $50 cost for the ENERGY STAR refrigerator nor would it include the $39 cost to replace lost space heating.

The five cost effectiveness tests shown in the above table were developed in California in the mid-1980s. Up until recently, the TRC and the Societal Cost ("SC") tests were generally used to determine cost effectiveness of potential energy efficiency and DSM initiatives. The shift in recent years to the PAC test represents a lowering of the bar for what is deemed to be cost effective. In terms of energy policy goals, such as the proposed 2% incremental annual energy saving as recommended in the 2017 PEI Energy Strategy, the shift to the PAC test is a way of having more energy efficiency deemed to be cost effective so as to be able to achieve the policy goal.

The energy efficiency industry rationale for the shift to the PAC test is given in the middle of page 19 of efficiencyPEI's Evidence:

"While it is relatively straight-forward for the TRC to account for all costs, it is difficult to account for all benefits as this requires quantifying non-energy benefits (NEBs) for participants and the electric utility. Some of these NEBs include increased comfort and health for building occupants, improved worker productivity, decreased maintenance, improved electricity system planning and reliability, the utility's ability to match demand to available capacity, and increased productivity. Accounting for NEBs can be problematic and expensive, because quantifying NEBs is location-specific and not an exact science. Not including NEBs in the equation leads to inaccurate results by counting all costs, but only a portion of the benefits."

One of the problems with the above rationale for the use of the PAC test is that it is broad brush approach. For example, many of the NEBs, such as increased comfort and health for building occupants, are related to building envelope efficiency measures, but have little or no relevance to rebates for ENERGY STAR appliances.

However, the biggest problem with the use of the PAC test in Atlantic Canada is that it does not account for the cost to replace lost space heating. The cost to replace lost space heating is more important in Atlantic than for much of the rest of North America because:

- The heating season is longer in Atlantic Canada
- There is limited availability of natural gas in Atlantic Canada for space heating. Where natural gas is available in the rest of North America, it is usually a relatively low cost fuel for space heating
- There is less residential air conditioning in Atlantic Canada than in much of the rest of North America, both in terms of penetration and cooling degree days of demand (the relevance of air conditioning is that during the air conditioning season the extra heat given off by less efficient appliances and lighting represents an increase in air conditioning load)

Thus, in summary, Maritime Electric's approach uses the TRC test (or alternately, the SC test) as the determinant of cost effectiveness.

Testing for cost effectiveness should be done at the individual measure level

efficiencyPEI is seeking approval to do cost effectiveness testing at the portfolio level for future Plans. Maritime Electric's approach differs from the methodology of this request in that cost effectiveness testing is done at the individual measure level. In energy efficiency industry terminology, a program is made up of a group of measures, and a portfolio is made up of a group of programs. If testing is done at the portfolio level, with all the proposed measures bundled together, then the likely outcome is there will be measures approved for implementation that are not cost effective on their own.

The following two tables are intended to show how bundling for cost effectiveness testing can lead to non cost effective measures being approved for implementation. The first table shows a summary of Maritime Electric's cost effectiveness testing for a $5 rebate coupon for an LED light. As with the ENERGY STAR refrigerator rebate example, the dollar amounts are present value amounts. The full analysis was included in Maritime Electric's 2015 DSM Plan filing. The result for the TRC test shows this measure to be cost effective (i.e. the benefit / cost ratio is greater than 1.0) and thus Maritime Electric included it in its proposed 2015 DSM Plan.

BENEFIT COST ANALYSIS OF REBATE FOR REPLACING 43 Watt INCANDESCENT HALOGEN WITH 11 Watt LED

		Participant Cost test ($)	Utility Cost test ($)	Rate Impact test ($)	Total Resource Cost test ($)	Societal Cost test ($)
Benefits:	- Utility avoided generating capacity cost		10	10	10	10
	- Utility avoided T&D capacity cost		12	12	12	12
	- Utility avoided energy supply cost		16	16	16	16
	- Reduction in participant's bills	27				
	- avoided cost of incandescant halogen lamp	4			4	4
	- Incentive rebate to participant	5				
	- Value of avoided CO2 emissions					3
	total	36	39	39	43	46
Costs:	- Utility DSM program admin. costs		5	5	5	5
	- Utility DSM program rebate costs		5	5		
	- Revenue reduction to utility			24		
	- Participant's incremental capital cost	8			8	8
	- Cost to replace lost space heating	15			15	15
	total	23	10	34	28	28
	Net benefit (cost)	13	29	5	15	18
	Benefit / cost ratio	1.58	3.86	1.14	1.53	1.65

Note: In some cases the sum of columns and totals shown differ due to rounding.

The second table shows what happens when the potential ENERGY STAR refrigerator rebate measure (which has a benefit / cost ratio of less than 1.0 for the TRC test) is bundled with the LED $5 rebate coupon measure. This second table is based on an assumed program uptake of four LED rebate coupons for each ENERGY STAR refrigerator rebate coupon (i.e. the numbers in the ENERGY STAR refrigerator rebate table plus four times the numbers in the LED rebate table).

		Participant Cost test ($)	Utility Cost test ($)	Rate Impact test ($)	Total Resource Cost test ($)	Societal Cost test ($)
	BENEFIT COST ANALYSIS OF A BUNDLE CONSISTING OF ONE ENERGY STAR REFRIGERATOR REBATE + 4 LED REBATES					
Benefits:	- Utility avoided generating capacity cost		49	49	49	49
	- Utility avoided T&D capacity cost		57	57	57	57
	- Utility avoided energy supply cost		108	108	108	108
	- Reduction in participant's bills	179				
	- avoided cost of incandescant halogen lamp	16			16	16
	- Incentive rebate to participant	50				
	- Value of avoided CO2 emissions					23
	total	246	214	214	230	253
Costs:	- Utility DSM program admin. costs		30	30	30	30
	- Utility DSM program rebate costs		50	50		
	- Revenue reduction to utility			157		
	- Participant's incremental capital cost	82			82	82
	- Cost to replace lost space heating	99			99	99
	total	181	80	237	211	211
	Net benefit (cost)	65	134	(23)	20	42
	Benefit / cost ratio	1.36	2.67	0.90	1.09	1.20

Note: In some cases the sum of columns and totals shown differ due to rounding.

The column for the TRC test in the above table shows that the bundle is cost effective (benefit / cost ratio greater than 1.0), which would lead to the approval and implementation of the ENERGY STAR refrigerator rebate coupon measure in addition to the LED rebate coupon measure, even though the ENERGY STAR refrigerator rebate coupon is not cost effective on its own.

The above example of bundling is based on a four to one ratio of LED rebate coupons to ENERGY STAR refrigerator rebate coupons. In reality the ratio would be more like 100 to 1, assuming 50,000 LED rebates annually and 500 refrigerator rebates annually for efficiencyPEI's proposed Plan. Thus there would be room to bundle a number of other non cost effective measures with the LED lighting rebate coupon measure, with a corresponding increase in the implementation of measures that are not cost effective on their own.

<u>Conclusion</u>

Maritime Electric views the Total Resource Cost test, applied at the individual program level, as the most appropriate basis upon which to assess the cost-benefit of any planned DSM or energy efficiency programs. The Company considers the target spending level proposed in efficiencyPEI's three year plan to be appropriate and fully supports the focus on LED lighting as the most effective means to achieve the program goals.

From: Spencer Campbell
Sent: Wednesday, December 05, 2018 9:02 AM
To: 'Jim Gogan' <jim@bretonlawgroup.com>
Subject: Synapse - Commission Supplemental IR's

Jim as requested, please find attached.

Spencer

From: Jim Gogan [mailto:jim@bretonlawgroup.com]
Sent: Monday, November 26, 2018 5:56 PM
To: Spencer Campbell <scampbell@stewartmckelvey.com>
Cc: Mike Proud (mpproud@gov.pe.ca) <mpproud@gov.pe.ca>; Kim Horrelt <kdhorrelt@gov.pe.ca>; Cora Porter (CPorter@efficiencyns.ca) <CPorter@efficiencyns.ca>; Allan Crandlemire (alcrandlemire@gmail.com) <alcrandlemire@gmail.com>; Janet MacDonald <janet@bretonlawgroup.com>
Subject: Synapse - Commission Supplemental IR's
Importance: High

Good evening Spencer

The Commission Consultant, Synapse, has issued supplemental IRs to PEIEC. These IRs are scheduled to be returned to the board on November 30.

Three specific IRs (IRs – IR 49; IR 50; an IR 51) require our client to provide responses to the Commission with information relating to your client. I have discussed this matter with the Counsel for the Commission. Given that the PEIEC doesn't have this information within its own records, Ms. McKenna has requested that we reach out directly to MECL requesting that they provide the information that PEIEC can then incorporate into its IR responses. I'm attaching copies of these IRs for your reference.

With regard to IR 51 we are seeking only a response with regard to whether or not MECL has an earnings adjustment mechanism in place. Similarly with IR 50, please advise if MECL has any form of performance incentive mechanism in operation. We are seeking a full response with regard to IR 49.

Given the very tight timeframe, I be grateful if you could forward these along to your client requesting that they provide this information to me as soon as possible. Should your client anticipate any difficulty in complying with this timeline I would appreciate if you would let me know immediately. Otherwise I look forward to receiving this information as soon as possible.

As always, I would be pleased discuss this further with you at your convenience.

Regards

Jim

THE BRETON LAW GROUP

James R. Gogan, Partner
tel 902-563-1000 I fax 902-563-1113 I direct 902-563-5920
292 Charlotte Street, Suite 300
Sydney, NS B1P 1C7

www.bretonlawgroup.com
asst Terri Johnson I tel 902-563-5902

From: Spencer Campbell <scampbell@stewartmckelvey.com>
Sent: Thursday, January 24, 2019 2:53 PM
To: Roberts, Jason
Subject: FW: Synapse - Commission Supplemental IR's
Attachments: SYN IR 51.docx; SYN IR 49.docx; SYN IR 50.docx

** THIS IS AN EXTERNAL EMAIL ** Use caution before opening links / attachments. Never supply user ID/password information.

And this

From: Spencer Campbell
Sent: Wednesday, December 05, 2018 9:02 AM
To: 'Nicole McKenna' <nmckenna@csmlaw.com>
Subject: Synapse - Commission Supplemental IR's

Nicole FYI I just sent these to PEIEC's counsel.

Spencer

NON-CONFIDENTIAL

Request IR-49:

Please answer the following questions regarding MECL's most recent rate case filing.

- **a.** **Did MECL make adjustments to its sales forecasts to reflect anticipated customer adoption of distributed energy resources? If so, how were such adjustments made? Please provide a reference to all sections and exhibits in the rate case filing that pertain to load forecast adjustments for distributed energy resources.**
- **b.** **Did MECL make adjustments to its sales forecasts to reflect anticipated customer adoption of energy efficiency and conservation? If so, how were such adjustments made? Please provide a reference to all sections and exhibits in the rate case filing that pertain to these adjustments.**
- **c.** **Please provide a reference to all the sections and exhibits in the most recent rate case filing that pertain to estimates of future revenue requirements.**
- **d.** **Does MECL use a future test year?**
- **e.** **How many years of revenue requirements does the rate case forecast include?**
- **f.** **What assumptions are used in estimating the revenue requirements in the future test year?**
- **g.** **Are the revenue requirement forecasts based on inflation, and/or productivity, and/or some other index?**

Response IR-49

a.
MECL did not make any adjustments to its sales forecast to reflect anticipated customer adoption of distributed energy resources because the quantities involved are not material.

On average, MECL is experiencing an increase of 0.25 GWh annually in the amount of energy received from net metering customers. Most of this increase is from residential rooftop solar photovoltaic (PV) installations. The energy received represents an estimated 2/3 of the annual generation by a solar PV installation, and it does not reduce MECL's energy sales – rather it displaces purchases from NB Power at the wholesale price.

The other 1/3 of the annual generation by a solar PV installation is used directly by the customer (i.e. behind the meter) and represents an annual reduction in energy sales of 0.13 GWh. This is not considered significant when compared to the forecast increase in energy sales of approximately 30 GWh annually over the three year period (2019 – 2021) covered by MECL's November 2018 General Rate Application.

b.

The sales forecast shown in Schedule 7-3 of MECL's November 2018 General Rate Application has factored in (i.e. has been reduced by) efficiencyPEI's estimated savings due to their planned energy efficiency programs.

The table below shows the energy efficiency savings that were taken into account in preparing the sales forecast. It is based on information received from efficiencyPEI, and the following assumptions:

- efficiencyPEI's energy efficiency programs were assumed to start in October 2018
- MECL supplies 90% of the PEI electricity load, so 90% of efficiencyPEI's estimated savings were assumed to apply to MECL

Year	**Residential (GWh)**	**General Service (GWh)**	**Cumulative Total (GWh)**	**Year Over Year Change (GWh)**
2018	0.4	0.3	0.7	0.7
2019	2.3	2.1	4.4	3.7
2020	5.4	5.7	11.1	6.7
2021	9.0	10.7	19.7	8.6

c.

References to future revenue requirements for the years 2019 – 2021 can be found in the Company's November 2018 General Rate Application filing in the following sections:

- Section 7 – Energy Sales Forecast
- Section 14 – Financial Forecast
- Appendix 3 – Financial Statements

d.

Yes. Maritime Electric's revenue requirements for the years 2019 – 2021 are based upon projected sales, revenues and costs for those years.

e.

The Company's November 2018 General Rate Application filing includes three years of forecast revenue requirement for the period 2019 - 2021

f.

The assumptions or proposals used in forecasting revenue requirement in the Company's November 2018 General Rate Application filing for the period 2019 – 2021 are discussed throughout the application and include:

- Proposals with respect to the recovery of amounts on behalf of the Province of PEI (Section 4).
- Proposals with respect to the administration and recovery of certain regulatory deferral accounts such as the Energy Cost Adjustment Mechanism, Weather Normalization Reserve and Rate of Return Adjustment Reserve Account (Section 5).
- Proposals with respect to the recovery of depreciation on the Company's assets, including provisions for the recovery of costs associated with the planned decommissioning of the Charlottetown Thernal Generating Station (Sections 6 and 11 as well as Appendices 9 – 11).
- Assumptions with respect to annual sales growth levels for 2019 – 2021 (Section 7).
- Projected costs in 2019 – 2021 with respect to Generation, Transmission, Distribution and General Expenses (Sections 8, 9 and 10).
- Proposals with respect to the Company's target return on average common equity, target equity component and forecast debt financing costs for the years 2019 – 2021 (Section 12).
- Summary information showing the impact of the assumptions on revenue requirement throughout the application (Section 14)

g.

The revenue requirement forecasts are not directly linked to inflation or productivity indexes but are based upon the Company's projected costs for the 2019 – 2021 period. The projections reflect the various proposals throughout the application that impact revenue requirement. For the Company's projected capital and operating costs, estimates are based upon planned work activities in each of the years and those related costs reflect annual escalation estimates that align with anticipated labour cost increases and inflationary increases for material and other costs.

NON-CONFIDENTIAL

Request IR-50:

Does MECL currently have any form of performance incentive mechanisms in place? Is ePEI recommending some form of performance incentive mechanism? If so, please describe in detail.

Response IR-50

No.

NON-CONFIDENTIAL

Request IR-51:

Does MECL currently have any form of earnings adjustment mechanism in place? Is ePEI recommending some form of earnings adjustment mechanism? If so, please describe in detail.

Response IR-51

The Company Maritime Electric currently has a Rate of Return Adjustment (RORA) deferral account which requires the Company to return to customers 100 per cent of regulated earnings above the authorized ROE, currently set at 9.35 per cent.

In the November 2018 General Rate Application filing, the Company has proposed the adoption of an Earnings Sharing Mechanism in the form of a banding or allowable range of return on average common equity for 2019 and future years.

As outlined in Section 12 of Maritime Electric's November 2018 filing, the Company proposes the adoption of a symmetrical ESM with a deadband of ± 50 basis points around the proposed ROE of 9.35 per cent. Under this model, the Company would retain the benefit of surplus earnings and assume the risk of an earnings shortfall within the deadband from 8.85 per cent to 9.85 per cent.

For earnings greater than 9.85 per cent in a year, it is proposed to return those excess earnings to the customer. In addition, for earnings below 8.85 per cent, it is proposed that the Company would be permitted to establish a deferral account for the shortfall to provide the Company with an earned ROE of no less than 8.85 per cent for that year. The deferral amount would then be recovered in future years as approved by IRAC.

Schedule 13-13								
Annual Impact of Second Block and Service Charge Changes - Rural								
Consumption	**2019**		**2020**		**2021**		**3 Year Average**	
kWh	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**
7,800	$ (18.16)	(1.3)	$ (4.70)	(0.3)	$ -	-	$ (7.62)	(0.5)
30,008	$ (1.99)	(0.0)	$ (4.70)	(0.1)	$ 225.32	5.2	$ 72.88	1.7
42,009	$ 2.54	0.0	$ (4.70)	(0.1)	$ 417.54	7.2	$ 138.46	2.4
54,030	$ 29.96	0.4	$ (4.70)	(0.1)	$ 487.75	7.0	$ 171.00	2.4
90,060	$ 9.08	0.1	$ (4.70)	(0.0)	$ 708.00	6.3	$ 237.46	2.1
146,280	$ 53.96	0.3	$ (4.70)	(0.0)	$ 885.00	5.0	$ 311.42	1.8

Schedule 13-14								
Annual Impact of Second Block and Service Charge Changes - Urban								
Consumption	**2019**		**2020**		**2021**		**3 Year Average**	
kWh	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**
7,800	$ 5.34	0.4	$ -	-	$ -	-	$ 1.78	0.1
30,008	$ 21.51	0.5	$ -	-	$ 225.32	5.2	$ 82.28	1.9
42,009	$ 26.04	0.5	$ -	-	$ 417.54	7.2	$ 147.86	2.6
54,030	$ 53.46	0.8	$ -	-	$ 487.75	7.0	$ 180.40	2.6
90,060	$ 32.58	0.3	$ -	-	$ 708.00	6.3	$ 246.86	2.2
146,280	$ 77.46	0.4	$ -	-	$ 885.00	5.0	$ 320.82	1.8

	2016	2017	2018	2019	2020	2021
Consumption - kWh	7,800	7,800	7,800	7,800	7,800	7,800
Service Charge per month	$ 26.92	$ 26.92	$ 26.92	$ 24.57	$ 24.57	$ 24.57
Basic Energy Charge per kWh	$ 0.132000	$ 0.137500	$ 0.140900	$ 0.143800	$ 0.147600	$ 0.149900
ECAM Charge per kWh	0.002058	0.001188	0.000575	0.003643	0.0017840	0.0014750
Provincial Costs Recoverable per kWh	0.005360	0.005360	0.005360	-	-	-
Provincial Energy Efficiency Program per kWh	-	-	-	0.000700	0.0008000	0.0009000
Cable Contingency Fund per kWh	0.000270	0.000270	0.000270	-	-	-
RORA per kWh	(0.004097)	(0.004732)	(0.003445)	(0.002504)	(0.0025040)	(0.0025040)
Total Energy Charge per kWh	$ 0.1356	$ 0.1396	$ 0.1437	$ 0.1456	$ 0.1477	$ 0.1498

SCHEDULE 15-2						
Annual Cost for Rural Residential Customer (650kWh per Month/7,800 kWh per Year)						
	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Service Charge	$ 323.04	$ 323.04	$ 323.04	$ 294.84	$ 294.84	$ 294.84
Basic Energy Charge	1,029.60	1,072.50	1,099.02	1,121.64	1,151.28	1,169.22
ECAM Charge	16.05	9.27	4.49	28.42	13.92	11.51
Provincial Costs Recoverable	41.81	41.81	41.81	-	-	-
Provincial Energy Efficiency Program	-	-	-	5.46	6.24	7.02
Cable Contingency Fund	2.11	2.11	2.11	-	-	-
RORA	(31.96)	(36.91)	(26.87)	(19.53)	(19.53)	(19.53)
Sub-total	1,380.66	1,411.82	1,443.60	1,430.83	1,446.75	1,463.06
HST*	199.05	211.77	216.54	214.63	217.01	219.46
Provincial Clean Energy Rebate**	-	-	(74.70)	(113.60)	(115.19)	(116.82)
Total Annual Cost	**$ 1,579.70**	**$ 1,623.59**	**$ 1,585.43**	**$ 1,531.86**	**$ 1,548.58**	**$ 1,565.70**
Percentage Annual Increase (%)	**2.7%**	**2.8%**	**-2.4%**	**-3.4%**	**1.1%**	**1.1%**

* HST Rate increased from 14% to 15% effective October 1, 2016

** Effective July 16, 2018 on first 2,000 kWh of consumption

	2016	2017	2018	2019	2020	2021
Consumption - kWh	7,800	7,800	7,800	7,800	7,800	7,800
Service Charge per month	$ 24.57	$ 24.57	$ 24.57	$ 24.57	$ 24.57	$ 24.57
Basic Energy Charge per kWh	$ 0.132000	$ 0.137500	$ 0.140900	$ 0.143800	$ 0.147600	$ 0.149900
ECAM Charge per kWh	0.002058	0.001188	0.000575	0.003643	0.0017840	0.0014750
Provincial Costs Recoverable per kWh	0.005360	0.005360	0.005360	-	-	-
Provincial Energy Efficiency Program per kWh	-	-	-	0.000700	0.0008000	0.0009000
Cable Contingency Fund per kWh	0.000270	0.000270	0.000270	-	-	-
RORA per kWh	(0.004097)	(0.004732)	(0.003445)	(0.002504)	(0.0025040)	(0.0025040)
Total Energy Charge per kWh	$ 0.1356	$ 0.1396	$ 0.1437	$ 0.1456	$ 0.1477	$ 0.1498

SCHEDULE 15-3						
Annual Cost for Urban Residential Customer (650kWh per Month/7,800 kWh per Year)						
	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Service Charge	$ 294.84	$ 294.84	$ 294.84	$ 294.84	$ 294.84	$ 294.84
Basic Energy Charge	1,029.60	1,072.50	1,099.02	1,121.64	1,151.28	1,169.22
ECAM Charge	16.05	9.27	4.49	28.42	13.92	11.51
Provincial Costs Recoverable	41.81	41.81	41.81	-	-	-
Provincial Energy Efficiency Program	-	-	-	5.46	6.24	7.02
Cable Contingency Fund	2.11	2.11	2.11	-	-	-
RORA	(31.96)	(36.91)	(26.87)	(19.53)	(19.53)	(19.53)
Sub-total	1,352.46	1,383.62	1,415.40	1,430.83	1,446.75	1,463.06
HST*	194.98	207.54	212.31	214.63	217.01	219.46
Provincial Clean Energy Rebate**	-	-	(74.70)	(113.60)	(115.19)	(116.82)
Total Annual Cost	**$ 1,547.44**	**$ 1,591.16**	**$ 1,553.00**	**$ 1,531.86**	**$ 1,548.58**	**$ 1,565.70**
Percentage Annual Increase (%)	**2.7%**	**2.8%**	**-2.4%**	**-1.4%**	**1.1%**	**1.1%**

* HST Rate increased from 14% to 15% effective October 1, 2016

** Effective July 16, 2018 on first 2,000 kWh of consumption

	2016	2017	2018	2019	2020	2021
Consumption - kWh	3,900	3,900	3,900	3,900	3,900	3,900
Service Charge per month	$ 26.92	$ 26.92	$ 26.92	$ 24.57	$ 24.57	$ 24.57
Basic Energy Charge per kWh	$ 0.132000	$ 0.137500	$ 0.140900	$ 0.143800	$ 0.147600	$ 0.149900
ECAM Charge per kWh	0.002058	0.001188	0.000575	0.003643	0.0017840	0.0014750
Provincial Costs Recoverable per kWh	0.005360	0.005360	0.005360	-	-	-
Provincial Energy Efficiency Program per kWh	-	-	-	0.000700	0.000800	0.000900
Cable Contingency Fund per kWh	0.000270	0.000270	0.000270	-	-	-
RORA per kWh	(0.004097)	(0.004732)	(0.003445)	(0.002504)	(0.0025040)	(0.0025040)
Total Energy Charge per kWh	$ 0.1356	$ 0.1396	$ 0.1437	$ 0.1456	$ 0.1477	$ 0.1498

SCHEDULE 15-2

Annual Cost for Rural Residential Customer (325kWh per Month/3,900 kWh per Year)

	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Service Charge	$ 323.04	$ 323.04	$ 323.04	$ 294.84	$ 294.84	$ 294.84
Basic Energy Charge	514.80	536.25	549.51	560.82	575.64	584.61
ECAM Charge	8.03	4.63	2.24	14.21	6.96	5.75
Provincial Costs Recoverable	20.90	20.90	20.90	-	-	-
Provincial Energy Efficiency Program	-	-	-	2.73	3.12	3.51
Cable Contingency Fund	1.05	1.05	1.05	-	-	-
RORA	(15.98)	(18.45)	(13.44)	(9.77)	(9.77)	(9.77)
Sub-total	851.85	867.44	883.32	862.84	870.80	878.96
HST*	122.81	130.12	132.50	129.43	130.62	131.84
Provincial Clean Energy Rebate**	-	-	(37.35)	(56.80)	(57.60)	(58.41)
Total Annual Cost	**$ 974.66**	**$ 997.55**	**$ 978.47**	**$ 935.47**	**$ 943.83**	**$ 952.39**
Percentage Annual Increase (%)	**2.2%**	**2.3%**	**-1.9%**	**-4.4%**	**0.9%**	**0.9%**

* HST Rate increased from 14% to 15% effective October 1, 2016

** Effective July 16, 2018 on first 2,000 kWh of consumption

	2016	2017	2018	2019	2020	2021
Consumption - kWh	3,900	3,900	3,900	3,900	3,900	3,900
Service Charge per month	$ 24.57	$ 24.57	$ 24.57	$ 24.57	$ 24.57	$ 24.57
Basic Energy Charge per kWh	$ 0.132000	$ 0.137500	$ 0.140900	$ 0.143800	$ 0.147600	$ 0.149900
ECAM Charge per kWh	0.002058	0.001188	0.000575	0.003643	0.0017840	0.0014750
Provincial Costs Recoverable per kWh	0.005360	0.005360	0.005360	-	-	-
Provincial Energy Efficiency Program per kWh	-	-	-	0.000700	0.000800	0.000900
Cable Contingency Fund per kWh	0.000270	0.000270	0.000270	-	-	-
RORA per kWh	(0.004097)	(0.004732)	(0.003445)	(0.002504)	(0.0025040)	(0.0025040)
Total Energy Charge per kWh	$ 0.1356	$ 0.1396	$ 0.1437	$ 0.1456	$ 0.1477	$ 0.1498

SCHEDULE 15-3						
Annual Cost for Urban Residential Customer (325kWh per Month/3,900 kWh per Year)						
	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Service Charge	$ 294.84	$ 294.84	$ 294.84	$ 294.84	$ 294.84	$ 294.84
Basic Energy Charge	514.80	536.25	549.51	560.82	575.64	584.61
ECAM Charge	8.03	4.63	2.24	14.21	6.96	5.75
Provincial Costs Recoverable	20.90	20.90	20.90	-	-	-
Provincial Energy Efficiency Program	-	-	-	2.73	3.12	3.51
Cable Contingency Fund	1.05	1.05	1.05	-	-	-
RORA	(15.98)	(18.45)	(13.44)	(9.77)	(9.77)	(9.77)
Sub-total	823.65	839.24	855.12	862.84	870.80	878.96
HST*	118.74	125.89	128.27	129.43	130.62	131.84
Provincial Clean Energy Rebate**	-	-	(37.35)	(56.80)	(57.60)	(58.41)
Total Annual Cost	**$ 942.40**	**$ 965.12**	**$ 946.04**	**$ 935.47**	**$ 943.83**	**$ 952.39**
Percentage Annual Increase (%)	**2.3%**	**2.4%**	**-2.0%**	**-1.1%**	**0.9%**	**0.9%**

* HST Rate increased from 14% to 15% effective October 1, 2016

** Effective July 16, 2018 on first 2,000 kWh of consumption

	2016	2017	2018	2019	2020	2021
Consumption - kWh	11,700	11,700	11,700	11,700	11,700	11,700
Service Charge per month	$ 26.92	$ 26.92	$ 26.92	$ 24.57	$ 24.57	$ 24.57
Basic Energy Charge per kWh	$ 0.132000	$ 0.137500	$ 0.140900	$ 0.143800	$ 0.147600	$ 0.149900
ECAM Charge per kWh	0.002058	0.001188	0.000575	0.003643	0.0017840	0.0014750
Provincial Costs Recoverable per kWh	0.005360	0.005360	0.005360	-	-	-
Provincial Energy Efficiency Program per kWh	-	-	-	0.000700	0.0008000	0.0009000
Cable Contingency Fund per kWh	0.000270	0.000270	0.000270	-	-	-
RORA per kWh	(0.004097)	(0.004732)	(0.003445)	(0.002504)	(0.0025040)	(0.0025040)
Total Energy Charge per kWh	$ 0.1356	$ 0.1396	$ 0.1437	$ 0.1456	$ 0.1477	$ 0.1498

SCHEDULE 15-2						
Annual Cost for Rural Residential Customer (975 kWh per Month/11,700 kWh per Year)						
	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Service Charge	$ 323.04	$ 323.04	$ 323.04	$ 294.84	$ 294.84	$ 294.84
Basic Energy Charge	1,544.40	1,608.75	1,648.53	1,682.46	1,726.92	1,753.83
ECAM Charge	24.08	13.90	6.73	42.62	20.87	17.26
Provincial Costs Recoverable	62.71	62.71	62.71	-	-	-
Provincial Energy Efficiency Program	-	-	-	8.19	9.36	10.53
Cable Contingency Fund	3.16	3.16	3.16	-	-	-
RORA	(47.93)	(55.36)	(40.31)	(29.30)	(29.30)	(29.30)
Sub-total	1,909.46	1,956.21	2,003.87	1,998.83	2,022.71	2,047.17
HST*	275.28	293.43	300.58	299.82	303.41	307.08
Provincial Clean Energy Rebate**	-	-	(112.05)	(170.40)	(172.79)	(175.23)
Total Annual Cost	**$ 2,184.75**	**$ 2,249.64**	**$ 2,192.40**	**$ 2,128.25**	**$ 2,153.33**	**$ 2,179.01**
Percentage Annual Increase (%)	**2.9%**	**3.0%**	**-2.5%**	**-2.9%**	**1.2%**	**1.2%**

* HST Rate increased from 14% to 15% effective October 1, 2016

** Effective July 16, 2018 on first 2,000 kWh of consumption

	2016	2017	2018	2019	2020	2021
Consumption - kWh	11,700	11,700	11,700	11,700	11,700	11,700
Service Charge per month	$ 24.57	$ 24.57	$ 24.57	$ 24.57	$ 24.57	$ 24.57
Basic Energy Charge per kWh	$ 0.132000	$ 0.137500	$ 0.140900	$ 0.143800	$ 0.147600	$ 0.149900
ECAM Charge per kWh	0.002058	0.001188	0.000575	0.003643	0.0017840	0.0014750
Provincial Costs Recoverable per kWh	0.005360	0.005360	0.005360	-	-	-
Provincial Energy Efficiency Program per kWh	-	-	-	0.000700	0.0008000	0.0009000
Cable Contingency Fund per kWh	0.000270	0.000270	0.000270	-	-	-
RORA per kWh	(0.004097)	(0.004732)	(0.003445)	(0.002504)	(0.0025040)	(0.0025040)
Total Energy Charge per kWh	$ 0.1356	$ 0.1396	$ 0.1437	$ 0.1456	$ 0.1477	$ 0.1498

SCHEDULE 15-3						
Annual Cost for Urban Residential Customer (975 kWh per Month/11,700 kWh per Year)						
	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Service Charge	$ 294.84	$ 294.84	$ 294.84	$ 294.84	$ 294.84	$ 294.84
Basic Energy Charge	1,544.40	1,608.75	1,648.53	1,682.46	1,726.92	1,753.83
ECAM Charge	24.08	13.90	6.73	42.62	20.87	17.26
Provincial Costs Recoverable	62.71	62.71	62.71	-	-	-
Provincial Energy Efficiency Program	-	-	-	8.19	9.36	10.53
Cable Contingency Fund	3.16	3.16	3.16	-	-	-
RORA	(47.93)	(55.36)	(40.31)	(29.30)	(29.30)	(29.30)
Sub-total	1,881.26	1,928.01	1,975.67	1,998.83	2,022.71	2,047.17
HST*	271.22	289.20	296.35	299.82	303.41	307.08
Provincial Clean Energy Rebate**	-	-	(112.05)	(170.40)	(172.79)	(175.23)
Total Annual Cost	**$ 2,152.48**	**$ 2,217.21**	**$ 2,159.97**	**$ 2,128.25**	**$ 2,153.33**	**$ 2,179.01**
Percentage Annual Increase (%)	**2.9%**	**3.0%**	**-2.6%**	**-1.5%**	**1.2%**	**1.2%**

* HST Rate increased from 14% to 15% effective October 1, 2016

** Effective July 16, 2018 on first 2,000 kWh of consumption

APPENDIX 4
Forecast Monthly ECAM Calculation - January 1, 2019 to December 31, 2021

Energy Cost Adjustment Mechanism	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
Purchased Energy Costs	6,922,291	6,607,082	6,789,421	6,817,174	5,617,290	5,548,280	6,564,372	6,305,014	5,280,490	4,895,225	5,891,330	7,699,426	74,937,396
Lepreau Energy Costs	2,104,480	2,044,495	2,106,770	1,603,399	1,994,372	2,069,107	2,074,263	2,070,819	2,051,786	2,069,398	2,049,416	2,081,885	24,320,190
Generation Fuel Costs-PEI Plants	156,665	75,315	75,315	38,849	38,849	6,000	37,256	37,256	42,466	38,849	85,839	156,665	789,327
PEI Plant Operating Costs	319,766	319,766	319,766	319,766	319,766	319,766	319,766	319,766	319,766	319,766	319,766	319,766	3,837,192
Less: Insurance, Property Tax & Training	(74,107)	(74,107)	(74,107)	(74,107)	(74,107)	(74,107)	(74,107)	(74,107)	(74,107)	(74,107)	(74,107)	(74,107)	(889,280)
Amortization - Pt Lepreau Deferred Charge & DSM	21,700	21,700	21,700	21,700	21,700	21,700	21,700	21,700	21,700	21,700	21,700	21,700	260,400
Renewable Energy Costs	2,493,266	1,877,736	2,559,195	2,028,087	1,959,690	1,824,852	1,173,754	1,486,127	2,046,812	2,767,282	2,689,450	2,382,172	25,288,424
	11,944,062	10,871,988	11,798,060	10,754,869	9,877,561	9,715,599	10,117,005	10,166,576	9,688,913	10,038,114	10,983,395	12,587,508	128,543,648
Net Purchased & Produced Energy - kWh (NPP)	133,226,295	119,699,961	126,670,133	104,682,589	104,839,593	101,394,508	108,537,685	108,781,691	100,480,485	104,770,591	114,569,834	137,381,398	1,365,034,762
Base Rate/kWh	0.09161	0.09161	0.09335	0.09335	0.09335	0.09335	0.09335	0.09335	0.09335	0.09335	0.09335	0.09335	0.09303
Base Energy Costs	12,204,861	10,965,713	11,824,657	9,772,120	9,786,776	9,465,177	10,131,993	10,154,771	9,379,853	9,780,335	10,695,094	12,824,553	126,985,903
Difference Between Actual & Base Energy Costs	(260,799)	(93,726)	(26,597)	982,749	90,785	250,421	(14,988)	11,805	309,060	257,779	288,301	(237,046)	1,557,745
Opening Balance - ECAM	4,639,432	4,308,208	4,144,735	3,712,614	4,295,662	4,024,056	3,929,945	3,562,963	3,204,543	3,146,280	3,059,362	2,988,312	4,639,432
Additions/(Reductions)	(260,799)	(93,726)	(26,597)	982,749	90,785	250,421	(14,988)	11,805	309,060	257,779	288,301	(237,046)	1,557,745
Rebated/(Collected) From Ratepayer	(70,425)	(69,748)	(405,523)	(399,701)	(362,392)	(344,532)	(351,995)	(370,224)	(367,323)	(344,698)	(359,351)	(422,224)	(3,868,135)
Closing Balance - ECAM	4,308,208	4,144,735	3,712,614	4,295,662	4,024,056	3,929,945	3,562,963	3,204,543	3,146,280	3,059,362	2,988,312	2,329,042	2,329,042
Cost to Residential Customer (650 kWh/Month)	$ 0.37	$ 0.37	$ 2.37	$ 2.37	$ 2.37	$ 2.37	$ 2.37	$ 2.37	$ 2.37	$ 2.37	$ 2.37	$ 2.37	$ 24.43

Energy Cost Adjustment Mechanism	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
Purchased Energy Costs	7,678,129	7,561,945	7,084,442	7,445,959	6,509,760	5,911,913	6,991,323	6,534,569	4,961,937	4,523,655	5,441,764	7,477,537	78,122,934
Lepreau Energy Costs	2,084,650	2,022,142	2,081,984	1,630,926	1,960,551	2,014,682	2,012,648	2,010,443	2,008,125	2,007,950	2,007,440	2,005,457	23,846,996
Generation Fuel Costs-PEI Plants	179,718	74,889	74,889	27,900	27,900	6,000	46,277	46,277	6,000	27,900	27,900	179,718	725,368
PEI Plant Operating Costs	313,636	313,636	313,636	313,636	313,636	313,636	313,636	313,636	313,636	313,636	313,636	313,636	3,763,635
Less: Insurance, Property Tax & Training	(76,330)	(76,330)	(76,330)	(76,330)	(76,330)	(76,330)	(76,330)	(76,330)	(76,330)	(76,330)	(76,330)	(76,330)	(915,959)
Amortization - Pt Lepreau Deferred Charge & DSM	21,700	21,700	21,700	21,700	21,700	21,700	21,700	21,700	21,700	21,700	21,700	21,700	260,400
Renewable Energy Costs	2,474,655	1,922,213	2,603,931	1,961,433	1,980,129	1,852,629	1,182,045	1,584,431	2,835,860	3,624,530	3,741,525	3,241,382	29,004,763
	12,676,158	11,840,196	12,104,253	11,325,225	10,737,346	10,044,231	10,491,299	10,434,725	10,070,929	10,443,040	11,477,635	13,163,100	134,808,138
Net Purchased & Produced Energy - kWh (NPP)	136,700,888	126,702,409	128,383,321	106,164,477	106,896,439	104,247,577	111,704,189	110,354,259	103,036,640	107,401,413	118,119,855	141,542,636	1,401,254,102
Base Rate/kWh	0.09335	0.09335	0.09475	0.09475	0.09475	0.09475	0.09475	0.09475	0.09475	0.09475	0.09475	0.09475	0.09449
Base Energy Costs	12,761,028	11,827,670	12,164,320	10,059,084	10,128,438	9,877,458	10,583,972	10,456,066	9,762,722	10,176,284	11,191,856	13,411,165	132,400,062
Difference Between Actual & Base Energy Costs	(84,870)	12,526	(60,067)	1,266,140	608,909	166,773	(92,673)	(21,341)	308,207	266,756	285,779	(248,064)	2,408,076
Opening Balance - ECAM	2,329,042	1,786,169	1,345,229	1,081,489	2,147,048	2,574,397	2,568,858	2,300,200	2,093,759	2,218,306	2,312,565	2,418,155	2,329,042
Additions/(Reductions)	(84,870)	12,526	(60,067)	1,266,140	608,909	166,773	(92,673)	(21,341)	308,207	266,756	285,779	(248,064)	2,408,076
Rebated/(Collected) From Ratepayer	(458,003)	(453,466)	(203,673)	(200,581)	(181,560)	(172,312)	(175,985)	(185,101)	(183,660)	(172,498)	(180,189)	(219,227)	(2,786,254)
Closing Balance - ECAM	1,786,169	1,345,229	1,081,489	2,147,048	2,574,397	2,568,858	2,300,200	2,093,759	2,218,306	2,312,565	2,418,155	1,950,864	1,950,864
Cost to Residential Customer (650 kWh/Month)	$ 2.37	$ 2.37	$ 1.16	$ 1.16	$ 1.16	$ 1.16	$ 1.16	$ 1.16	$ 1.16	$ 1.16	$ 1.16	$ 1.16	$ 16.33

Energy Cost Adjustment Mechanism	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
Purchased Energy Costs	7,247,900	6,901,790	6,521,690	5,472,462	5,548,266	5,534,653	6,822,568	6,302,974	5,180,683	4,641,111	5,741,403	7,803,356	73,718,856
Lepreau Energy Costs	2,001,801	1,999,772	1,998,820	1,997,150	1,995,838	1,994,168	1,992,857	1,991,366	1,989,696	1,988,385	1,986,715	1,985,403	23,921,973
Generation Fuel Costs-PEI Plants	163,066	54,614	54,614	6,000	6,000	6,000	47,669	47,669	6,000	6,000	6,000	163,066	566,699
PEI Plant Operating Costs	326,022	326,022	326,022	326,022	326,022	326,022	326,022	326,022	326,022	326,022	326,022	326,022	3,912,270
Less: Insurance, Property Tax & Training	(80,856)	(80,856)	(80,856)	(80,856)	(80,856)	(80,856)	(80,856)	(80,856)	(80,856)	(80,856)	(80,856)	(80,856)	(970,268)
Amortization - Pt Lepreau Deferred Charge & DSM	21,700	21,700	21,700	21,700	21,700	21,700	21,700	21,700	21,700	21,700	21,700	21,700	260,400
Renewable Energy Costs	3,419,069	2,688,487	3,520,420	2,721,761	2,715,423	2,552,317	1,675,082	2,147,138	2,838,025	3,802,766	3,747,160	3,272,136	35,099,785
	13,098,703	11,911,530	12,362,411	10,464,239	10,532,395	10,354,005	10,805,042	10,756,014	10,281,271	10,705,129	11,748,145	13,490,829	136,509,714
Net Purchased & Produced Energy - kWh (NPP)	140,163,048	124,189,700	130,003,827	107,576,339	109,140,373	106,182,309	113,827,475	112,386,444	104,749,278	109,655,384	120,879,628	144,341,139	1,423,094,943
Base Rate/kWh	0.09475	0.09475	0.09591	0.09591	0.09591	0.09591	0.09591	0.09591	0.09591	0.09591	0.09591	0.09591	0.09569
Base Energy Costs	13,280,449	11,766,974	12,468,667	10,317,647	10,467,653	10,183,945	10,917,193	10,778,984	10,046,503	10,517,048	11,593,565	13,843,759	136,182,387
Difference Between Actual & Base Energy Costs	(181,745)	144,556	(106,256)	146,593	64,742	170,060	(112,151)	(22,969)	234,767	188,081	154,579	(352,929)	327,327
Opening Balance - ECAM	1,950,864	1,540,782	1,459,418	1,181,876	1,159,892	1,072,226	1,097,838	838,199	660,105	740,952	784,382	787,634	1,950,864
Additions/(Reductions)	(181,745)	144,556	(106,256)	146,593	64,742	170,060	(112,151)	(22,969)	234,767	188,081	154,579	(352,929)	327,327
Rebated/(Collected) From Ratepayer	(228,337)	(225,920)	(171,285)	(168,577)	(152,408)	(144,448)	(147,489)	(155,124)	(153,921)	(144,651)	(151,327)	(184,741)	(2,028,228)
Closing Balance - ECAM	1,540,782	1,459,418	1,181,876	1,159,892	1,072,226	1,097,838	838,199	660,105	740,952	784,382	787,634	249,964	249,964
Cost to Residential Customer (for 650 kWh)	$ 1.16	$ 1.16	$ 0.96	$ 0.96	$ 0.96	$ 0.96	$ 0.96	$ 0.96	$ 0.96	$ 0.96	$ 0.96	$ 0.96	$ 11.91