MARITIME ELECTRIC
A FORTIS COMPANY

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The Island Regulatory and Appeals Commission

July 3, 2015

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

Dear Mr. Lanigan:

DSM Filing Docket UE21406
Response to Interrogatories from Mr. Roger King

Please find attached the Company's response to the Interrogatories filed by Mr. Roger King with respect to the DSM filing. An electronic copy will follow shortly.

Yours truly,

MARITIME ELECTRIC

Jason C. Roberts
Director, Regulatory & Financial Planning

JCR32
Enclosure

MARITIME ELECTRIC
A FORTIS COMPANY

Via email: randjking@pei.sympatico.ca

July 3, 2015

Mr. Roger King
519 Simpsons Mill Rd
Hunter River PE C0A 1N0

Dear Mr. King:

DSM Filing Docket UE21406
Response to Interrogatories

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1. Is the plan appropriate?

Response – 1:
Yes, as explained in the following responses.

1.(a) The proposed plan costs are high. Prior to the Energy Accord, the MECL annual budget for DSM was $600K – this plan is $2.2M per year.

Response – 1.(a):
The proposed Plan costs are higher due to higher costs for the lighting measure and the inclusion of the two heat pump measures, which were not part of the Plan proposed prior to the Energy Accord for 2011 – 2015.

Lighting measures are the major source of peak load reduction for both the Plan that Maritime Electric ("MECL" or the "Company") proposed in 2010 for 2011 – 2015 and the current proposed Plan for 2015 – 2020. The attached Schedule 1 shows that the cost to reduce the system peak by 1.0 kW through lighting rebate coupons is higher for the current proposed Plan - approximately $1,000/kW versus approximately $220/kW for Plan proposed for 2011 – 2015. The reasons for this are as follows:

- The current proposed Plan assumes 50% free riders under the LED rebate coupon measure; i.e. for each LED that replaces a 43 Watt incandescent bulb it assumes that there will be an LED that will be used to replace a 13 Watt CFL bulb, with a resulting minimal peak load reduction for the CFL replacement. The Plan proposed for 2011 – 2015 did not take free riders into account which results in the $/kW cost for the lighting measure in the 2015 – 2020 Plan being higher by a factor of 2.
- For the 2015 – 2020 Plan it is assumed that 33% of the LEDs that replace incandescent bulbs in general lighting applications will be on at system peak. For the 2011 – 2015 Plan, the portion of the rebated lighting that was assumed would be on at system peak was higher – a weighted average of 64% - driven by the expectation that 75% of holiday lighting would be on at peak. This results in the $/kW cost for the lighting measure in the 2015 – 2020 Plan being higher by another factor of 2.
- The amount of the rebate coupon is higher for the proposed 2015 – 2020 Plan, although this is partially offset by a lower administration cost.

For the two proposed heat pump measures, the average cost for peak load reduction is $1,000/kW (not including the ongoing bill credits past 2020).

1.(b) Benefit/cost ratios of around 1.5 are explained suggesting that with a total spend of $11M over five years, rate reduction costs of around $17M should be evident. However, the plan proposes that "the impact on rates will be minimal" and shows that customers will have an added debt of $8M by 2020 to be paid off by 2035. A question remains: will the resulting ECAM rate adjustment and the 7% interest rate applied to this declining debt effectively negate the $17M return?

Response – 1.(b):

For most of the benefit cost tests, the costs include more than the $11 million of proposed expenditures. Thus it is not appropriate to divide the $11 million of proposed expenditures by a benefit cost ratio.

The test for evaluating the impact on rates is the Rate Impact Measure (RIM) test. In addition to the approximate $11 million in Plan expenditures, the RIM test also treats as a cost to the utility the reduction in revenue due to decreased usage of electricity as a result of the Plan.

The attached Schedule 2 shows an overall benefit cost ratio of 1.19 for the RIM tests for the three proposed Plan measures, and an overall net benefit of $5.1 million.

The attached Schedule 3 shows an estimated financing cost of $4.5 million based on the proposed deferred recovery of Plan expenditures so as to match the recovery of costs with the realization of benefits over the lives of the proposed measures. However, it is not appropriate to consider the $4.5 million estimated financing cost as an additional cost to customers in the context of the benefit cost analysis. The benefit cost analysis is done on a present value basis, and thus the calculations reflect the financing cost associated with the program's cash flows over its life.

1.(c) If LED light bulbs provide a consumer pay-back (as claimed by the manufacturers) I suggest that an electric utility should not be subsidizing both consumer and manufacturer on a low risk purchase? Also as energy used and peak load are growing, how will the impact of the light bulb program be measured?

Response – 1.(c):

In an ideal world consumers would include the cost of the electricity used by a light bulb in their purchasing decision, and not base it solely on the upfront cost. However, the reality is that for many consumers the higher upfront cost for a LED light bulb is a deterrent. Rather than viewing the rebate provided by the utility as subsidy, MECL believes it should be viewed as a lower cost alternative to the cost of supplying the additional electricity that would be used by the less efficient light bulb, as determined through benefit cost analysis.

Given that electricity usage is growing, the Company will endeavour to measure the impact of the LED rebate coupon program indirectly through analysis of the coupons redeemed.

1.(d) Two heat pump rebates are proposed. While there is a DSM case for replacing (and not duplicating) resistance (base-board) space heating with a more efficient heat pump, I suggest that an electric utility should not be advocating for electric space heating (which will increase peak load) and again should not be subsidizing both consumer and manufacturer on a low risk purchase?

Response – 1.(d):
The growth in electric resistance heating and the installation of mini-split heat pumps in recent years has been driven by market forces. Consumers have been responding to higher furnace oil prices and a growing awareness of the potential environmental liability associated with furnace oil tanks.

MECL's proposed tie-in with the OEE grant program for "most efficient" heat pumps is not considered to be advocating for electric space heating. Only the top 10% of heat pumps in terms of efficiency (currently a Heating Season Performance Factor of greater than 8.35 for Climate Region 5) are eligible for the OEE grant. The objective of the OEE grant program is to partially offset the higher upfront cost of purchasing a "most efficient" heat pump and having it installed by a qualified installer. The objective of MECL's two proposed heat pump measures is to reduce the impact of electric heat on system peak when consumers decide to use electricity for space heating. For homes with electric resistance heating, the objective is to have the heat pump operating at time of system peak, and thus displacing electric resistance heating. For homes with oil heating, the objective is to have the heat pump turned off at system peak, and the oil furnace supplying all of the space heating.

2. Does the Plan prioritize?

Response – 2:
Yes, as explained in the following.

2.(a) DSM was introduced in the 2004 Renewable Energy Act to control peak load. In 2010 the peak load was 205 MW; this is reported to be now 260 MW – a growth of 55 MW or 28%. This growth is driving the recent concern for the urgency of the new mainland cables and the prospect of having to purchase an additional Island based 50 MW generator. Islanders and businesses together consume around 1100 GWh of energy each year so our average power computes to 130 MW but our peak load is two times this average. A load capacity of around 50% suggests an inefficient electricity delivery system.

This first-for-some-time DSM plan has to consider peak load control as a priority. A common DSM action to reduce peak load is to spread the time over which the peak loads occur. Adjusting customer rates (independent of energy cost) to encourage use at "off-peak" or "Time of Wind" periods should show a benefit/cost ratio better than 1.5. Equally, the importance of time-spreading loads within a single residence should be explained in the context of a demand charge applicable to some tariffs.

Response – 2.(a):
In 2014 PEI used 1,395 GWh of electricity and the peak load was 254 MW resulting in an annual load factor of 63%.

The system load factor is a function of the loads served. For Canadian electric utilities, the extent of electric heat penetration impacts the load factor, with higher penetration of electric heat typically resulting in lower load factor. For PEI, the penetration of electric heat is estimated to be approximately 10%. The table below shows the lower load factors for provinces where electric heat is the predominant form of space heating.

Annual load factor for Provinces with high electric heat penetration				
Province	**For 12 months ending**	**Annual energy (GWh)**	**Peak load (MW)**	**Annual load factor (%)**
Quebec	December 31, 2014	190,000	38,700	56
Manitoba	March 31, 2014	25,500	4,720	62
New Brunswick	March 31, 2014	14,100	3,060	53
Newfoundland	December 31, 2014	7,460	1,535	56

MECL's proposed Plan is focused on controlling the peak load. The objective of the two heat pump measures is to reduce the impact of electric heat on system peak, as explained in the response to Question 1(d). The LED rebate coupon measure is also intended to reduce peak load, because the peak occurs for the hour ending 6:00 p.m. in December or January, after sunset.

Maritime Electric's position on Time-of-Use rates is that the difference between the Company's on-peak and off-peak energy supply costs is not large enough to incent customers to shift a significant portion of their on-peak usage to off-peak hours. The Company finds support for this position in the 2014 Annual Report of the Office of the Auditor General of Ontario, which included the results of its audit of Ontario's Smart Metering Initiative (pp 362-406). The Auditor General's report is available at www.auditor.on.ca/en/reports_en/en14/311en14.pdf

In its report, the Auditor General found that the "Time-of-Use (TOU) pricing model has had minor impact on reducing peak demand" (p 368).

> "In 2013, separate studies released by the Ontario Power Authority and the OEB [Ontario Energy Board] indicated that TOU pricing had a modest impact on residential ratepayers, reducing their peak demand by only about 3%, but a limited or unclear effect on small businesses, and none at all on energy conservation. Our [the Auditor General] review also found that:
>
> - Of about 1.8 million ratepayers on TOU rates that we reviewed, only 35% of residential ratepayers and 19% of small businesses reduced their consumption during On-Peak periods, while a majority of them (65% of residential and 81% of small businesses) did not.
> - About 77,000 ratepayers with smart meters paid set rather than TOU rates because they signed fixed-price contracts with electricity retailers, who do not charge based on time of use. Consumption patterns of retail and TOU ratepayers were about the same, suggesting that TOU pricing provided no more incentive to change usage behavior than retail contracts." (p 368)

The Auditor General also found that:

> "With respect to the TOU rates, the greater the difference between On-Peak and Off-Peak rates, the higher the likelihood that ratepayers will change their usage patterns. However, we noted that the difference between On-Peak and Off-Peak rates in Ontario may not be significant enough to provide ratepayers with an incentive to change their electricity-use behavior. Specifically:
>
> - When TOU pricing was introduced in 2006, the initial On-Peak – to – Off-Peak ratio was three-to-one, meaning that On-Peak power cost three times as much as Off-Peak. However, the ratio had dropped to 1.8-to-one at the time of our audit due to the impact of the substantial growth of the Global Adjustment…

- In 2010, the OEB commissioned an external consultant to study TOU rates around the world and assess the appropriateness of Ontario's TOU rates. Consistent with our observation above, the consultant reported that Ontario's On-Peak – to – Off-Peak ratio was "low relative to TOU programs in other jurisdictions and will likely produce modest ratepayer response or bill savings." The average ratio elsewhere was four-to-one, compared to Ontario's 1.8-to-one. The Ontario ratio could deliver only about a 1% drop in the average ratepayer's peak demand, while a four-to-one ratio could potentially yield a drop three times greater." (p 381)

The difference between Maritime Electric's on-peak and off-peak energy supply costs is such that the resulting difference between on-peak and off-peak rates under TOU pricing would be less than two-to-one, and thus the Company expects that the benefits from TOU pricing would be less than the costs to implement it.

3. Is the Plan progressive?
The proposed plan appears to be a fixed, five year plan. How will progressive, future ideas and opportunities be introduced? Over the next five years we should expect technology changes and hopefully some positive results from the Powershift Atlantic program defining how smart metering might be introduced. Our Energy Commission report encouraged the introduction of thermal storage and time-shifted Domestic Hot Water heating – has there been any progress here?

Response – 3:
MECL expects to file annual reports with IRAC on Plan progress and results. The Company expects that these reports will provide an opportunity to propose changes to the Plan based on results to date and as new opportunities arise. An example is the proposed pilot phase for the first year of the thermostat control of heat pumps measure. At the end of the pilot phase, MECL will report the results to IRAC and recommend whether a full implementation is warranted for the following four years.

The PowerShift Atlantic Project showed that controlling loads in near real time in response to varying loads and wind generation is technically feasible. However, the cost of integration and communications makes it uneconomic to implement at this time.

SCHEDULE 1

Comparison of Lighting Measures

2015 Roger King questions
15-06-15

Schedule 1
COMPARISON OF LIGHTING MEASURES

		Proposed Plan for years 2011 - 2015					Proposed Plan for years 2015 - 2020		
		LED holiday lighting	CFL BR30 reflector	Bare CFL	LED pot light	Totals / weighted averages	LED replacing 43 W incd	LED replacing 13 W CFL (free riders)	Totals
Expected peak reduction	MW	6.00	0.48	2.65	0.52	9.65	5.87	-	5.87
Incandescent usage	Watts	35.0	65.0	60.0	65.0		43.0		
LED / CFL usage	Watts	3.5	16.0	15.0	11.0		11.0		
Reduction	Watts	31.5	49.0	45.0	54.0		32.0		
Portion that are on at peak	%	75	33	50	33	64	33		
T&D losses at system peak	%	15	15	15	15		15.7		
Total number required	x 1,000	216	25	100	25		464	464	
Admin cost per bulb / string	$	2.78	1.90	2.65	2.10	2.66	1.50	1.50	
Rebate amount per bulb	$	3.00	3.25	1.50	12.00	3.09	5.00	5.00	
Total admin cost	$ x 1,000	600	48	265	52	964	696	696	1,392
Total rebate coupons cost	$ x 1,000	648	82	150	298	1,177	2,320	2,320	4,639
Total measure cost	$ x 1,000	1,247	130	415	350	2,142	3,015	3,015	6,031
Cost to reduce peak by 1 kW	**$ / kW**					222			1,027

SCHEDULE 2

Results of Rate Impact Measure Tests
For 2015-2020 plan
Proposed Measures

2015 Roger King questions
15-06-15

Schedule 2
RESULTS OF RATE IMPACT MEASURE TESTS FOR 2015 - 2020 PLAN PROPOSED MEASURES

				(1)			(2)	(3)	1) + (2) + (3)
		$ 5.00 rebate coupon for LEDs			**Grants for "cold climate" heat pumps**				
		Replace 43 Watt incandesc with 11 Watt LED (Appx 3)	Replace 13 Watt CFL with 11 Watt LED (Appx 4)	Combined (Appx 5)	Net increase (Appx 13)	Existing uptake (Appx 13)	Combined (Appx 13)	**Thermostat control of heat pumps** (Appx 14)	**Total**
			(free riders)			(free riders)			
Benefits:	- Utility avoided generating capacity cost	10.22	0.64	5.43	2,031		2,031	1,016	
	- Utility avoided T&D capacity cost	11.99	0.75	6.37	2,383		2,383	1,191	
	- Utility avoided energy supply cost	16.38	1.02	8.70	341		341	341	
	- Reduction in participant's bills								
	- Incentive rebate to participant								
	- Value of avoided CO2 emissions								
	total	38.59	2.41	20.50	4,755	0	4,755	2,548	
Costs:	- Utility program administration costs	1.50	1.50	1.50	150	188	338	150	
	- Utility program rebate / grant costs	5.00	5.00	5.00	425	531	956	911	
	- Cost to implement thermostat control							500	
	- Revenue reduction to utility	23.85	1.49	12.67	496		496	497	
	- Participant's incremental capital cost								
	- Cost to replace lost space heating								
	total	30.35	7.99	19.17	1,071	719	1,790	2,058	
	Net benefit (cost)	8.24	(5.58)	1.33	3,684	(719)	2,966	491	
	Benefit / cost ratio	1.27	0.30	1.07	4.44	-	2.66	1.24	
Number per year (x 1,000)		92,800	92,800	185,600	160	200	360	810	
Number of years		5	5	5	5	5	5	4	
Overall benefits ($ x 1,000)		17,906	1,119	19,025	3,804	-	3,804	8,256	31,085
Overall costs ($ x 1,000)		14,083	3,708	17,791	857	719	1,576	6,666	26,033
Net benefit / (cost) ($ x 1,000)		3,823	(2,589)	1,234	2,947	(719)	2,228	1,590	5,053
Overall benefit / cost ratio									1.19

SCHEDULE 3

Financing of Deferred Recovery

2015 Roger King questions
15-06-15

Schedule 3
FINANCING OF DEFERRED RECOVERY

Year	Plan expenditures (Appx 15) ($ x 1,000)	Recovery through rates (Appx 16) ($ x 1,000)	Unrecovered amount at year end ($ x 1,000)	Carrying cost (financing) at 7.0 % ($ x 1,000)
2015	100		100	
2016	1,656		1,756	4
2017	2,198	322	3,632	189
2018	2,279	573	5,338	314
2019	2,360	824	6,875	427
2020	2,441	1,074	8,242	529
2021	334	1,325	7,252	542
2022	334	1,157	6,429	479
2023	334	1,157	5,605	421
2024	334	1,157	4,782	364
2025	334	1,157	3,959	306
2026	334	1,157	3,136	248
2027	334	1,036	2,434	195
2028	334	916	1,852	150
2029	334	795	1,390	113
2030	334	675	1,050	85
2031	324	550	824	66
2032	243	522	544	48
2033	162	392	314	30
2034	81	262	133	16
2035		133	0	5
	15,186	15,186		4,530